DELIVERED BY HAND

July 25, 2003

Board of Commissioners of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NF A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland Power's 2004 Capital Budget Application

A. General

Enclosed are 12 copies each of:

1. Newfoundland Power's 2004 Capital Budget Application and supporting materials in 4 volumes (the "Application"); and
2. Filing Contents of the Application (the "Filing Contents")

Order No. P.U. 36 (2002-2003) (the "Order") materially increased capital budget filing requirements for Newfoundland Power. The Application comprehensively responds to this change in filing requirements.

The following describes the Company's approach to organization of the Application and the contents of the 4 volumes. It is intended to assist in understanding the organization of the Application which is substantially changed from recent capital budget applications of Newfoundland Power.

Join us in the fight against cancer.

Telephone: (709) 737-5859 *Email: palteen@newfoundlandpower.com* *Fax: (709) 737-2974*

B. Organization of the Application

General Approach: Newfoundland Power's organization of the Application continues to reflect the nature of its utility assets and its management of those assets. Project categories are substantially the same as those used in recent capital budget applications. This will provide a level of consistency which allows reasonable year over year comparisons.

The Order, and particularly the *Conditions for Future Filings* (Schedule C to the Order), required specific information to be provided with the Application. This information has been provided.

To meet the requirements set out in the Order and provide a reasonable measure of organization of the increased volume of information, the Company chose to layer the overall presentation. The primary layer of information is contained in Volume I. The second layer of information is contained in Volumes II, III, and IV.

Volume I: Volume I contains the Application and supporting Schedules in the format which has historically been submitted to the Board by Newfoundland Power.

Volume I also contains the following reports which the Board has specifically ordered Newfoundland Power file with the Application:

> *2003 Capital Expenditure Status Report:* filed in compliance with paragraph 6, page 28 of the Order;
>
> *Information Technology Strategy 2004 – 2008:* filed in compliance with paragraph 7, page 29 of the Order;
>
> *2004 Capital Budget Plan:* filed in compliance with paragraph 8, page 29 of the Order; and
>
> *Changes in Deferred Charges 2003 – 2004:* filed in compliance with paragraph 5(i), page 120 of Order No. P.U. 19 (2003).

Volume I also contains the prefiled evidence for three witness panels proposed to be called by Newfoundland Power in support of the Application. The prefiled evidence is somewhat shorter than in previous capital budget filings. This is the result of a combination of the increased filing requirements and the Company's desire to avoid undue repetition.

Volumes II, III and IV: Volumes II, III and IV of the Application contain expenditure details, reports and studies. This information is provided to meet the requirements contained in the Order.

The information contained in Volumes II, III, and IV is divided into capital budget categories, with appendices for those projects for which additional detailed information is required.

Attachments are used to separate supporting material which is typically in the form of engineering reports and studies.

Accessing information in the Application: The material contained in Volume 1, particularly Schedule B to the Application, provides project descriptions, operating experience, project justifications and future commitments. For many, but not all, projects reference will be made in Schedule B to a specific Budget Category and Appendix contained in Volume II, III or IV. In that Appendix, further detail on the project can be found.

The interrelationship between Schedule B to the Application and the expenditure details and supporting materials contained in Volumes II, III and IV may be best described by way of example.

At page 10 of Schedule B to the Application is the description of the Energy Supply project *Hydro Plants Facility Rehabilitation* in an amount of $1,122,000. In that description there is the projected cost breakdown of the total project as specifically required by the *Conditions for Future Filings* and a reference to Volume II, Energy Supply, Appendix 1. In Volume II, Energy Supply, Appendix 1 further expenditure detail by site or electrical component, as appropriate, is provided. Appendix 1 has two attachments. The first is an engineering report dealing the condition of the Topsail Hydro Plant governor, protection and control systems. The second is an engineering report with respect to the condition of the turbine and the stationary seals at the Morris Hydro Plant.

C. Filing Details and Circulation

The enclosed material has been provided in binders with appropriate tabbing. For convenience, additional materials such as Responses to Requests for Information will be provided on three-hole punched paper.

The Filing Contents are provided as a tool to assist the Board in referencing the contents of the Application. The Filing Contents is organized consistent with the tabs contained in the 4 volumes that comprise the Application. Where the description of the contents behind each tab is not apparent from the tab itself, the contents are indicated in ***red*** in the Filing Contents.

A PDF file of the Application will be forwarded to the Board in due course.

A copy of the Application has been forwarded directly to Maureen Greene, Q.C. of Newfoundland & Labrador Hydro and Dennis Browne, Q.C.

D. Concluding

We trust the foregoing and enclosed are found to be in order.

If you have any questions on the Application, please contact us at your convenience.

Yours very truly,

Peter Alteen
Corporate Counsel
& Secretary

Enclosures

c. Maureen P. Greene, Q.C.
Newfoundland & Labrador Hydro

Dennis Browne, Q.C.
Browne Fitzgerald Morgan & Avis

Newfoundland Power
2004 Capital Budget Application
Filing Contents

Volume I
Application, Schedules and Prefiled Evidence

Application

Schedule A ***2004 Capital Budget Summary***
Schedule B ***Capital Projects Explanations***
Schedule C ***Estimate of Future Required Expenditures on 2004 Projects***
Schedule D ***2002 Rate Base***

2003 Capital Expenditure Status Report

Information Technology Strategy 2004 - 2008

2004 Capital Budget Plan

Changes in Deferred Charges 2003 - 2004

Prefiled Evidence: Ludlow / Delaney

Prefiled Evidence: Mulcahy / Collins

Prefiled Evidence: Perry / Hutchens

Volume II
Expenditure Details, Reports and Studies

Energy Supply

Appendix 1 ***Hydro Plant Facility Rehabilitation***

Attachment A ***Topsail Plant Governor, Protection and Control Systems Engineering Review***
Attachment B ***Morris Plant Turbine and Stationary Seal Inspection***

Appendix 2 ***New Chelsea Hydro Plant Refurbishment***

Attachment A ***New Chelsea Plant Planned Refurbishment 2004***

Substations

Appendix 1 ***Rebuild Substations***

Appendix 2 ***Replacement and Standby Substation Equipment***

Appendix 3 ***Feeder Additions due to Load Growth and Reliability***

Appendix 4 ***Increase Corner Brook Transformer Capacity***

  Attachment A ***Power Transformer Study, City of Corner Brook***

Transmission

Appendix 1 ***Rebuild Transmission Lines***

  Attachment A ***St. John's Transmission Ampacity Review***

Volume III
Expenditure Details, Reports and Studies

Distribution

Appendix 1 ***Meters***

Appendix 2 ***Rebuild Distribution Lines***

  Attachment A ***Distribution Inspection Standards***
  Attachment B ***Distribution Lightning Arrestors***
  Attachment C ***Distribution Insulator Replacement Program***
  Attachment D ***Current Limiting Fuses***
  Attachment E ***Automatic Sleeve Replacement***
  Attachment F ***Porcelain Cutout Replacement***
  Attachment G ***Underground Distribution System Replacements in the St. John's Area***

Appendix 3 ***Distribution Reliability Initiative***

  Attachment A ***A Review of Reliability (Wesleyville – 02 Feeder)***
  Attachment B ***A Review of Reliability (Bay Roberts – 04 Feeder)***
  Attachment C ***Pulpit Rock Substation Loading and Reliability***

Appendix 4 ***Feeder Additions and Upgrades to Accommodate Growth***

  Attachment A ***Conception Bay South Planning Study***

General Property

Appendix 1 ***Tools & Equipment***

Appendix 2 ***Real Property***

Transportation

Appendix 1 ***Purchase Vehicles and Aerial Devices***

  Attachment A ***Details 2004 Capital Budget Vehicle Budget***

Volume IV
Expenditure Details, Reports and Studies

Information Systems

Newfoundland Power
2004 Capital Budget Application
Filing Contents

Volume I
Application, Schedules and Prefiled Evidence

Volume II
Expenditure Details, Reports and Studies

Appendix 4 *Increase Corner Brook Transformer Capacity*

Attachment A *Power Transformer Study, City of Corner Brook*

Transmission

Appendix 1 *Rebuild Transmission Lines*

Attachment A *St. John's Transmission Ampacity Review*

Volume III
Expenditure Details, Reports and Studies

Distribution

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Appendix 2 *Real Property*

Transportation

Appendix 1 *Purchase Vehicles and Aerial Devices*

Attachment A *Details 2004 Capital Budget Vehicle Budget*

Volume IV
Expenditure Details, Reports and Studies

Information Systems

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

2004 Capital Budget Application

NEWFOUNDLAND
POWER
A FORTIS COMPANY

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

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

THE APPLICATION OF Newfoundland Power Inc. ("Newfoundland Power") **SAYS THAT:**

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994.*

2. Schedule A to this Application is a summary of Newfoundland Power's 2004 Capital Budget in the amount of $53,909,000 which includes an estimated amount of $1,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2004. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application is a list of those 2004 capital expenditures, exclusive of general expenses capital, which comprise Newfoundland Power's 2004 Capital Budget.

4. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2004 Capital Budget but will not be completed in 2004.

5. Schedule D of this Application shows Newfoundland Power's actual average rate base for 2002 of $573,337,000.

6. The proposed expenditures as set out in Schedules A, B and C to this Application are necessary for Newfoundland Power to continue to provide service and facilities which are reasonably safe and adequate and just and reasonable as required pursuant to Section 37 of the Act.

7. Communication with respect to this Application should be forwarded to the attention of Peter Alteen and Brock Myles, Counsel to Newfoundland Power.

8. Newfoundland Power requests that the Board make an Order:

   (a) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2004 of the improvements and additions to its property in the amount of $53,909,000; and

   (b) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2002 in the amount of $573,337,000.

DATED at St. John's, Newfoundland and Labrador, this 25th day of July, 2003.

NEWFOUNDLAND POWER INC.

Peter Alteen and Brock Myles
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland
A1B 3P6

Telephone:	(709) 737-5859
Telecopier:	(709) 737-2974

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

AFFIDAVIT

I, Barry Perry, of St. John's in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer, of Newfoundland Power Inc.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's
in the Province of Newfoundland and
Labrador this 25th day of July, 2003,
before me:

Barry Perry

Barrister

Barry Perry

Newfoundland Power Inc.
2004 Capital Budget
Budget Summary
(000s)

Energy Supply	$6,945
Substations	5,199
Transmission	2,315
Distribution	27,636
General Property	709
Transportation	3,487
Telecommunications	120
Information Systems	3,948
Unforeseen Items	750
General Expenses Capital	2,800
Total	**$ 53,909**

Newfoundland Power Inc.
2004 Capital Budget

ENERGY SUPPLY

	(000s)	Details on Page
HYDRO PLANTS - FACILITY REHABILITATION	$1,122	10
NEW CHELSEA – HYDRO PLANT REFURBISHMENT	3,973	12
PURCHASE PORTABLE DIESEL GENERATION	1,700	14
MAJOR ELECTRICAL EQUIPMENT REPAIRS	150	16
TOTAL - ENERGY SUPPLY	**$6,945**	

Newfoundland Power Inc.
2004 Capital Budget

SUBSTATIONS

	(000s)	Details on Page
REBUILD SUBSTATIONS	$1,023	18
REPLACEMENT & STANDBY SUBSTATION EQUIPMENT	1,314	20
TRANSFORMER COOLING REFURBISHMENT	398	22
PROTECTION & MONITORING IMPROVEMENTS	80	24
DISTRIBUTION SYSTEM FEEDER REMOTE CONTROL	1,000	26
FEEDER ADDITIONS DUE TO LOAD GROWTH AND RELIABILITY	200	28
INCREASE CORNER BROOK TRANSFORMER CAPACITY	1,184	30
TOTAL - SUBSTATIONS	$5,199	

Newfoundland Power Inc.
2004 Capital Budget

TRANSMISSION

	(000s)	Details on Page
REBUILD TRANSMISSION LINES	$2,315	32
TOTAL - TRANSMISSION	**$2,315**	

Newfoundland Power Inc.
2004 Capital Budget

DISTRIBUTION

	(000s)	Details on Page
EXTENSIONS	$4,956	34
METERS	1,174	36
SERVICES	1,946	38
STREET LIGHTING	1,242	40
TRANSFORMERS	4,965	42
RECONSTRUCTION	2,461	44
ALIANT POLE PURCHASE	4,044	46
TRUNK FEEDERS		
Rebuild Distribution Lines	4,137	47
Relocate/Replace Distribution Lines For Third Parties	235	50
Distribution Reliability Initiative	949	52
Feeder Additions and Upgrades to Accommodate Growth	677	54
Switch Replacement & Upgrade Underground Distribution – Water Street, St. John's	750	56
INTEREST DURING CONSTRUCTION	100	58
TOTAL - DISTRIBUTION	**$27,636**	

Newfoundland Power Inc.
2004 Capital Budget

GENERAL PROPERTY

	(000s)	Details on Page
TOOLS AND EQUIPMENT	535	59
ADDITIONS TO REAL PROPERTY	174	61
TOTAL - GENERAL PROPERTY	**$709**	

Newfoundland Power Inc.
2004 Capital Budget

TRANSPORTATION

	(000s)	Details on Page
PURCHASE VEHICLES AND AERIAL DEVICES	**$3,487**	62
TOTAL - TRANSPORTATION	**$3,487**	

Newfoundland Power Inc.
2004 Capital Budget

TELECOMMUNICATIONS

	(000s)	Details on Page
REPLACE/UPGRADE COMMUNICATIONS EQUIPMENT	$70	64
SUBSTATION TELEPHONE CIRCUIT PROTECTION	50	66
TOTAL - TELECOMMUNCIATIONS	**$120**	

Newfoundland Power Inc.
2004 Capital Budget

INFORMATION SYSTEMS

	(000s)	Details on Page
APPLICATION ENHANCEMENTS	$1,355	68
APPLICATION ENVIRONMENT	791	70
CUSTOMER SYSTEMS REPLACEMENT	226	72
NETWORK INFRASTRUCTURE	393	74
PERSONAL COMPUTER INFRASTRUCTURE	539	76
SHARED SERVER INFRASTRUCTURE	644	78
TOTAL – INFORMATION SYSTEMS	**$3,948**	

Newfoundland Power Inc.
2004 Capital Budget

UNFORESEEN ITEMS

	(000s)	Details on Page
ALLOWANCE FOR UNFORESEEN ITEMS	$750	80
TOTAL – UNFORESEEN ITEMS	**$750**	

ENERGY SUPPLY

Project Title: **Hydro Plants Facility Rehabilitation**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$1,122,000**

Project Description

This project is necessary for the replacement or rehabilitation of deteriorated hydro plant components that have been identified through routine inspections.

The work includes the replacement or rehabilitation of major components at the following plants: Pierres Brook, Topsail, Morris, Rattling Brook, Heart's Content and Victoria.

The project also includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to maintain environmental compliance. Details on various items are included in Volume II, Energy Supply, Appendix 1.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$655	-	-	-
Labour – Internal	277	-	-	-
Labour – Contract	76	-	-	-
Engineering	114	-	-	-
Other	-	-	-	-
Total	**$1,122**	**$3,013**	**$8,438**	**$12,573**

Operating Experience

The following table gives the expenditures for the past five years for work falling within this project.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$707	$1,670	$1,482	$2,031	$2,778

These facilities provide energy to the Island Interconnected electrical system. Maintaining these generating facilities and infrastructure reduces the need for additional, more expensive, generation capacity.

Project Justification

The Company's 23 hydroelectric plants range in age from the 103 year old Petty Harbour Plant to the 5 year old Rose Blanche Plant. The average age is 59 years.

Projects involving replacement and rehabilitation work, which are identified during ongoing inspections and maintenance activities, are necessary to the continued operation of hydroelectric generation facilities in a safe, reliable and environmentally compliant manner. The alternative to maintaining these facilities would be to retire them. These facilities produce a combined average annual production of 426 GWh. Replacing only the energy produced by these facilities by increasing production at the Holyrood generation facility would require approximately 700,000 barrels of fuel annually. At oil prices of $28 per barrel, this translates into approximately $20 million in annual fuel savings. Maintaining these generating facilities also contributes to system stability and, in many cases, provides local backup generation.

All significant expenditures on individual hydroelectric plants, such as the replacement of penstocks, surge tanks, runners, or forebays, are justified on the basis of maintaining access to hydroelectric generation at a cost that is lower than the cost of replacement options.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **New Chelsea Hydro Plant Refurbishment**

Location: **New Chelsea, Trinity Bay**

Classification: **Energy Supply**

Project Cost: **$3,973,000**

Project Description

This project involves the complete refurbishment of the New Chelsea hydroelectric generating station. Included in the scope of work is the replacement of the woodstave penstock with a steel pipeline, the replacement of a generator breaker, the rewind of the generator, the replacement of the protection and control systems, the replacement of the governor system and miscellaneous electrical and mechanical work associated with these larger systems.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$3,462	-	-	$3,462
Labour – Internal	260	-	-	260
Labour – Contract	-	-	-	-
Engineering	251	-	-	251
Other	-	-	-	-
Total	**$3,973**	**$0**	**$0**	**$3,973**

Operating Experience

The New Chelsea plant went into service in January 1957. The system has operated continuously since that time and provides normal production of 15.5 GWh of energy on an annual basis. In 1986 remote control through the SCADA system at the System Control Centre was added to the plant. With the exception of that upgrade there has been minimal other capital investment in this facility.

The woodstave penstock has reached a state where significant work is required to patch leaks that develop regularly. The water leaking from the penstock is cause for concern as it undermines the supporting structure of the penstock.

Project Justification

A detailed report, including site assessments completed by Professional Engineers, is included in Volume II, Energy Supply, Appendix 2.

New Chelsea generating station is one of the largest energy producers in Newfoundland Power's group of hydroelectric plants. The original equipment that comprises the plant is forty-eight years old and requires considerable effort to repair and replace components that fail in service, as replacement parts are generally not readily available. The equipment has exceeded its expected life and replacement must be addressed at this time.

The woodstave penstock has experienced failures in recent years that have allowed water to escape. As determined by a recent inspection, in various areas of the steel portion of the penstock the thickness of the wall is below the design parameters as a result of corrosion. The potential exists for damage to property and risk to employee and public safety if a catastrophic failure were to occur.

Concern also exists for the condition of the generator windings, which have exceeded their estimated life expectancy as established by the Institute of Electrical and Electronic Engineers (IEEE). As a result the project will include funds to allow for the rewind of the generator.

Due to age, the protection and control equipment, governor and AC station service equipment is obsolete. Technical support for the original electromechanical devices is very limited, and as a result the current equipment is a mix of technologies created by temporary repairs completed over the years.

The alternative to replacing the penstock and refurbishing this plant would be to retire it. This facility provides normal annual production of approximately 15.5 GWh. Replacing only the energy produced by this facility by increasing production at the Holyrood generation facility would require approximately 25,000 barrels of fuel annually. At a cost of $28 per barrel, this translates into a fuel saving of approximately $700,000 annually.

An economic analysis of the New Chelsea Hydroelectric system, considering this project and the expected capital and operating expenditures required over the next 25 years, indicates a positive net present value.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Purchase 2.5 MW Standby Portable Diesel**

Location: **Corporate**

Classification: **Energy Supply**

Project Cost: **$1,700,000**

Project Description

The project consists of the purchase of a second 2.5 MW portable diesel generation unit. The generator will be stationed during the winter months at Trepassey, except when it is required elsewhere for emergency backup. In the summer months, the unit will be moved as necessary to support construction or repair activities.

Project Cost
($000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$1,571	-	-	$1,571
Labour – Internal	88	-	-	88
Labour – Contract	-	-	-	-
Engineering	26	-	-	26
Other	15	-	-	15
Total	**$1,700**	**$0**	**$0**	**$1,700**

Operating Experience

The two portable generators that the Company previously owned have reached the end of their useful life and have been retired. The *"Portable Diesel Generation: Reliability Analysis Sizing and Unit Location Review"* and the *"Existing Portable Diesel Generation Condition Assessment and Review"* reports were previously filed in response to Request for Information PUB-4.1, Attachments A and B respectively, in the Newfoundland Power 2003 Capital Budget Application.

Project Justification

During the winter months portable generation is normally stationed at substations fed from a radial transmission line. However, when the need arises the units are deployed to areas affected by prolonged outages caused by major winter storms. In the summer time the units enable the Company to maintain energy supply to customers while upgrade or repair work is performed on de-energized electrical circuits. In addition, as the generation unit will normally be connected to the electrical system, it can also be called upon when needed to support system capacity requirements.

Newfoundland Power presently has one portable gas turbine and one portable diesel generator which is currently being manufactured for delivery in late 2003. The portable gas turbine, which is rated at 7.2 MW, is located at Grand Bay Substation in Port aux Basques, except when it is required for emergencies or construction elsewhere. The 2.5 MW portable diesel generation unit currently being manufactured will also be located at Port aux Basques, except when required elsewhere.

These generators will be available to Newfoundland and Labrador Hydro ("Hydro") under the Equipment Sharing Agreement between Hydro and the Company.

Except in the event of an emergency, the Company plans to locate the unit to be acquired in 2004 at Trepassey during the winter, which will maximize overall system reliability.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Major Electrical Equipment Repairs**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$150,000**

Project Description

This project is necessary to provide for the unanticipated cost of major equipment replacement or rehabilitation occasioned by deterioration or catastrophic failure. Major equipment includes transformers, generators and turbines.

Project Cost
($000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$145	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$150**	**$150**	**$450**	**$750**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$465	$51	$137	$707	$150

Project Justification

Past experience indicates that unforeseen equipment failures will occur. Projects covered by this budget item in the past include generator rewinding, power transformer rehabilitation, replacement of power connection cables and refurbishment of surge tank components.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

SUBSTATIONS

Project Title: **Rebuild Substations**

Location: **Grand Bay, Trepassey, Indian Cove, Port Blandford, Wheelers, Stamps Lane, Bay Roberts and Laurentian**

Classification: **Substations**

Project Cost: **$1,023,000**

Project Description

This project is necessary for the replacement of deteriorated and substandard substation infrastructure, such as bus structures, poles and support structures, equipment foundations, switches and fencing.

Replacement work will take place primarily at the 8 substations noted above, with additional minor work at 5 other substations.

Details are contained in Volume II, Substations, Appendix 1.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$600	-	-	-
Labour – Internal	242	-	-	-
Labour – Contract	3	-	-	-
Engineering	178	-	-	-
Other	-	-	-	-
Total	**$1,023**	**$550**	**$3,616**	**$5,189**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$201	$426	$1,191	$687	$452

Project Justification

The Company has 137 substations varying in age from 2 years to greater than 100 years. The book value of these substations is in excess of $100 million. Infrastructure to be replaced was identified as a result of monthly inspections and engineering studies. These expenditures will ensure reliable service and address safety concerns.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Replacement & Standby Substation Equipment**

Location: **Pepperell, Summerford, Milton, Bonavista, Glenwood, Boyd's Cove, Glovertown, Gambo, Laurentian, Gillams, Dunville, Cape Broyle, Greenhill and Mobile Substation P-435.**

Classification: **Substations**

Project Cost: **$1,314,000**

Project Description

This project is necessary for the replacement of obsolete and/or unreliable electrical equipment and the maintenance of appropriate levels of spare equipment for use during emergencies.

The locations where the work will be undertaken in 2004 are noted above. Details are contained in Volume II, Substations, Appendix 2.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$963	-	-	-
Labour – Internal	241	-	-	-
Labour – Contract	-	-	-	-
Engineering	110	-	-	-
Other	-	-	-	-
Total	**$1,314**	**$2,146**	**$8,065**	**$11,525**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$384	$313	$232	$2,716	$1,206

Project Justification

The Company has 137 substations. The major equipment items comprising a substation include power transformers, circuit breakers, reclosers, potential transformers and battery banks. In total the Company has approximately 190 power transformers, 400 circuit breakers, 200 reclosers, 340 voltage regulators, 220 potential transformers and 140 battery banks.

The need to replace equipment is determined on the basis of tests, inspections and the operational history of the equipment. The provision of adequate levels of spare equipment is based on past experience and engineering judgement, as well as a consideration of the impact the loss of a particular apparatus would have on the electrical system.

This project is justified based on the need to replace equipment to restore and maintain service. The budget estimate is based on equipment inspections and historical replacement requirements, as well as on assessments of the current stock of spare equipment

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Transformer Cooling Refurbishment**

Location: **Greenspond, Bishops Falls, Cobbs Pond and Humber**

Classification: **Substations**

Project Cost: **$398,000**

Project Description

This project occurs at the substations identified above and involves the replacement of power transformer cooling radiators that have begun to leak oil as a result of corrosion. This will also address environmental concerns of oil spills due to leaking equipment.

In 2004, radiators will be replaced on the following units:

Greenspond T1	Bishops Falls T1
Cobbs Pond T1	Humber T3

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$222	-	-	-
Labour – Internal	152	-	-	-
Labour – Contract	-	-	-	-
Engineering	24	-	-	-
Other		-	-	-
Total	**$398**	**$250**	**$750**	**$1,398**

Operating Experience

The original radiators supplied with the transformers when they were purchased were coated with primer and enamel based paint for protection from the elements. Exposure to our environment causes the radiators to rust and blister. Eventually the radiators begin to leak at the welded seams and through the thinner cooling panel surfaces.

The original radiators are being replaced with galvanized units, which provide enhanced rust resistance. The new radiators have a life expectancy in the range of 40 years.

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$15	$206	$0	$0	$0

Project Justification

The cost of this project is justified based on the need to replace equipment to maintain reliable service. Oil is used in a transformer as part of its electrical insulation system. An uncontrolled loss of oil would compromise that system with the resulting failure of the transformer and the interruption of service to customers.

The amounts budgeted are based on equipment inspections and historical replacement requirements, as well as the current inventory of backup equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Protection & Monitoring Improvements**

Location: **Goulds, Gander and Cobbs**

Classification: **Substations**

Project Cost: **$80,000**

Project Description

This project is necessary for the replacement and/or addition of protective relaying equipment required to maintain system protection and increase operating reliability.

In 2004 work will take place at Goulds involving the installation of a synchro check relay and at the Gander and Cobb's substations as a part of the Tap Changer Control Program.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$25	-	-	
Labour – Internal	25	-	-	
Labour – Contract	-	-	-	
Engineering	30	-	-	
Other	-	-	-	
Total	**$80**	**$45**	**$135**	**$260**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$196	$92	$283	$116	$430

Project Justification

This project will make improvements to the protection and monitoring systems of the selected substations to allow for the safe and reliable operation of these substations.

The project is justified on the basis of maintaining the reliability and safe operation of the electrical system

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Distribution System Feeder Remote Control**

Location: **Chamberlains, Pepperrell, Blaketown, Humber, Ridge Road, Bay Roberts, Bayview and Kelligrews substations.**

Classification: **Substations**

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

Project Description

This is a continuation of a project initiated in 2002. It involves replacing a number of aging, limited function, electromechanical feeder relays and oil-filled reclosers with modern multi-function electronic relays and reclosers that can be remotely controlled from the System Control Centre (SCC).

By the end of 2003, the System Control Centre (SCC) will have remote control over 40 feeders through new electronic feeder relays and over 30 feeders through reclosers.

In 2004, 25 feeder relays will be replaced at Chamberlains, Pepperrell, Blaketown, Humber, Ridge Road and Bay Roberts. There will be 6 reclosers replaced in Bayview and Kelligrews substations.

While expenditures are forecasted from 2005 to 2008, beyond 2004, specific locations have not been identified as future maintenance history and operating issues would need to be considered in deciding the actual locations.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$701	-	-	-
Labour – Internal	153	-	-	-
Labour – Contract	-	-	-	-
Engineering	146	-	-	-
Other	-	-	-	-
Total	**$1,000**	**$1,000**	**$4,500**	**$6,500**

Operating Experience

The Company’s electromechanical feeder relays and oil-filled reclosers are, on average, 25 years old and are nearing the end of their useful life. All will require replacement over the next few years.

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$0	$0	$0	$1,092	$1,200

Project Justification

This project is justified on the basis of improvements in safety, operating efficiencies, power system reliability improvements and a reduction in risk to the environment. The report which supports this project, *“Distribution Feeder Remote Control and Relay/Recloser Replacement Review”,* was previously filed in response to Request for Information PUB-9.3, in the Newfoundland Power 2002 Capital Budget Application.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Feeder Additions Due To Load Growth and Reliability**

Location: **Chamberlains and Pulpit Rock Substations**

Classification: **Substations**

Project Cost: **$200,000**

Project Description

This project is necessary for the addition of new equipment and/or upgrades in two substations to provide for increased loads due to customer growth.

This project includes the installation of a third 25 kV feeder at the Chamberlains substation and a third 12.5 kV feeder at the Pulpit Rock substation in order to accommodate growth, and reliability issues in the areas served by each substation.

Details are contained in Volume II, Substations, Appendix 3.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$128	-	-	-
Labour – Internal	43	-	-	-
Labour – Contract	-	-	-	-
Engineering	29	-	-	-
Other	-	-	-	-
Total	**$200**	**$344**	**$80**	**$624**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost

Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$159	$64	$282	$0	$0

Project Justification

The project is justified on the basis of accommodating customer load growth. The proper sizing of equipment is necessary to avoid overloading conductors and equipment and to maintain system reliability.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Increase Corner Brook Transformer Capacity**

Location: **Walbournes and Bayview Substations**

Classification: **Substations**

Project Cost: **$1,184,000**

Project Description

This project includes the installation of a new 66/12.5 kV 25 MVA substation transformer at Walbournes substation as a replacement for the existing 66/12.5 kV 20 MVA transformer, and then moving the existing Walbournes transformer to the Bayview substation.

Details are contained in Volume II, Substations, Appendix 4, Attachment A.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$913	-	-	$913
Labour – Internal	174	-	-	174
Labour – Contract	-	-	-	
Engineering	97	-	-	97
Other	-	-	-	-
Total	**$1,184**	**$0**	**$0**	**$1,184**

Operating Experience

The overall substation transformer loading in the City of Corner Brook is forecasted to exceed 100% capacity in the 2003 / 2004 winter season. This is based on a total substation transformer capacity of 68.3 MVA compared to a projected load of 68.4 MVA.

Project Justification

Load forecasts for the City of Corner Brook substations indicate that the combined load will exceed the combined capacity of the substation transformers. The addition of another transformer in the system will accommodate this increased load and represents the least cost solution to meeting the forecast load requirements for the city of Corner Brook substations.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

TRANSMISSION

Project Title: **Rebuild Transmission Lines**

Location: **Various**

Classification: **Transmission**

Project Cost: **$2,315,000**

Project Description

This project involves the replacement of poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections, engineering reviews and/or day to day operations.

The work includes major upgrades on transmission lines number 3L, 16L, 38L, 116L, 123L, 124L, 132L and 403L. Expenditures estimated at less than $50,000 for any one line will also take place on approximately 50 other lines.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$1,015	-	-	-
Labour – Internal	492	-	-	-
Labour – Contract	741	-	-	-
Engineering	67	-	-	-
Other	-	-	-	-
Total	**$2,315**	**$3,101**	**$18,018**	**$23,434**

Operating Experience

Many of the Company’s older transmission lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration and replacement is required to maintain the strength and integrity of the line. Thirty per cent of the Company’s 110 transmission lines are in excess of forty years of age. As well, inspections and testing activities have revealed significant increases in the quantities of corroded conductors in some locations. This is causing upward pressure on transmission line rebuild requirements.

The following table gives the expenditures for the past five years for this project.

Year	1999	2000	2001	2002	2003F
$000s	$1,509	$727	$2,289	$2,976	$4,241

Project Justification

This project is necessary to replace poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections in order to ensure that such lines provide reliable service to customers and are safe for both the public and line workers.

Detailed information on the projects is outlined in Volume II, Transmission, Appendix 1.

Future Commitments

None.

DISTRIBUTION

Project Title: **Extensions**

Location: **Various**

Classification: **Distribution**

Project Cost: **$4,956,000**

Project Description

This project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical distribution system. The project also includes upgrades to the capacity of existing lines to accommodate customers who increase their electrical load. The project includes labour, materials, and other costs to install poles, wires and related hardware.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$1,660	-	-	-
Labour – Internal	1,491	-	-	-
Labour – Contract	1,148	-	-	-
Engineering	558	-	-	-
Other	99	-	-	-
Total	**$4,956**	**$4,680**	**$11,215**	**$20,851**

Operating Experience

The project cost for the connection of new customers is calculated on the basis of historical data for specific operating areas. Historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average extension cost per customer. Unusually high and low data is excluded from the average. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by the Conference Board of Canada.

The following table shows the annual expenditure for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$2,800	$3,981	$5,404	$5,717	$5,184

Project Justification

This project is justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Meters**

Location: **Various**

Classification: **Distribution**

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

Project Description

This project includes the purchase and installation of meters for new customers and replacement meters for existing customers. The Company has previously purchased two types of meters, those that must be read manually and those that are capable of being read automatically, commonly referred to as AMR meters. In 2004 the Company proposes the purchase and installation of meters, as noted in the table below.

Program	Number of Meters
Regular Domestic Meters	8,000
AMR Meters	3,000

Project Cost

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$1,000	-	-	-
Labour – Internal	105	-	-	-
Labour – Contract	69	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,174**	**$699**	**$1,989**	**$3,862**

Operating Experience

The purchase of new meters is necessary to accommodate customer growth and to replace deteriorated meters. The quantity of meters for new customers is based on the Company's forecast of customer growth. The quantity for replacement purposes is determined using historical data for damaged meters and sampling results from previous years. Sampling is done in accordance with regulations under the Electricity and Gas Inspection Act.

The number of AMR meters required for safety and access issues is based on the Company's assessment of locations where these issues exist. See Volume III, Distribution, Appendix 1, for details.

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$560	$564	$569	$674	$674

Project Justification:

The requirement for regular domestic meters is based on customer requirements and Industry Canada regulations. The requirements for AMR meters are based on improving safety for employees, improving accuracy of reads and improving efficiency of operations.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Services**

Location: **Various**

Classification: **Distribution**

Project Cost: **$1,946,000**

Project Description

This project involves the installation of service wires to connect new customers to the electrical distribution system. Service wires are low voltage wires that connect the customer's electrical service equipment to the utility's transformers. Also included in this category is the replacement of existing service wires due to deterioration, failure or damage, as well as the installation of larger wires to accommodate customers' additional load.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$601	-	-	-
Labour – Internal	990	-	-	-
Labour – Contract	56	-	-	-
Engineering	280	-	-	-
Other	19	-	-	-
Total	**$1,946**	**$2,099**	**$5,233**	**$9,278**

Operating Experience

The project cost for the connection of new customers is calculated on the basis of historical data. For new services, historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average new service cost per customer. Unusually high and low data is excluded from the average. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate. A similar process is following for replacement services using historical actual expenditures to replace damaged or deteriorated service wires. Street light customers are excluded for the purpose of this calculation.

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$1,419	$1,532	$1,838	$1,843	$1,841

Project Justification

These projects are justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Street Lighting**

Location: **Various**

Classification: **Distribution**

Project Cost: **$1,242,000**

Project Description

This project involves the installation of new lighting fixtures, replacement of existing street light fixtures, and the provision of associated overhead and underground wiring. A street light fixture includes the light head complete with bulb, photocell and starter as well as the pole mounting bracket and other hardware. The project is driven by customer requests and historical levels of lighting fixture failures requiring replacement.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$695	-	-	-
Labour – Internal	345	-	-	-
Labour – Contract	144	-	-	-
Engineering	50	-	-	-
Other	8	-	-	-
Total	**$1,242**	**$1,091**	**$3,197**	**$5,530**

Operating Experience

The project cost is calculated on the basis of historical data. For new street lights, historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average cost per new customer. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate.

For replacement street lights, historical annual expenditures for replacement of damaged, deteriorated or failed street lights are adjusted for inflation and divided by the total number of customers served in each year to derive an average replacement street light cost per customer. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast of the total number of customers served to determine the budget estimate.

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$800	$911	$935	$1,199	$1,233

Project Justification

These projects are justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Transformers**

Location: **Various**

Classification: **Distribution**

Project Cost: **$4,965,000**

Project Description

This project includes the cost of purchasing transformers for customer growth and the replacement or refurbishment of units that have deteriorated or failed.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$4,965	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$4,965**	**$4,600**	**$12,760**	**$22,325**

Operating Experience

The project requirements can be divided into three categories as follows:

a) The number of transformers required for new customers is based on estimates for each of the Company's operating areas. The estimate is created by regional engineering personnel based upon the forecast number of new residential customers for each area and their judgement as to the additional number of transformers required for new general service customers based on a combination of historical experience and specific knowledge.

b) Replacement transformers are based on field surveys of rusty or deteriorated transformers.

c) The "other" category is for transformers required for conversions and upgrades, plus an allowance for contingency (burnouts and storm damage, etc.). This category is estimated on the basis of planned projects and historical data.

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$3,190	$4,243	$4,550	$5,194	$4,895

Project Justification

This project is required to provide and maintain service to new customers.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Reconstruction**

Location: **Various**

Classification: **Distribution**

Project Cost: **$2,461,000**

Project Description

This project involves the replacement of deteriorated or storm damaged distribution structures and electrical equipment. This project is generally comprised of a number of smaller projects that are identified during line inspections or recognized following operational problems. By their nature these are high priority projects that normally cannot be deferred to the next budget year. This project differs from the Rebuild Distribution Lines project which involves rebuilding sections of lines that are identified and planned in advance of budget preparation.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$526	-	-	-
Labour – Internal	1,098	-	-	-
Labour – Contract	510	-	-	-
Engineering	272	-	-	-
Other	55	-	-	-
Total	**$2,461**	**$2,644**	**$7,535**	**$12,640**

Operating Experience

The project cost is estimated on the basis of average historical expenditures related to unplanned repairs to distribution feeders.

The following table shows the expenditures for the past five years.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$2,222	$1,888	$2,547	$2,878	$2,745

Project Justification

These projects are justified on the basis of reliability and the need to replace damaged electrical equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Aliant Pole Purchase**

Location: **Corporate**

Classification: **Distribution**

Project Cost: **$4,044,000**

Project Description

This project covers the 2004 installment associated with the Support Structures Purchase Agreement entered into with Aliant Telecom Inc. in 2001.

Operating Experience

Not Applicable.

Project Justification

This project is necessary to comply with the terms of the Support Structures Purchase Agreement entered into by Newfoundland Power Inc. with Aliant Telecom Inc. covering the purchase of all joint-use poles within Newfoundland Power's service territory over a five year period.

Future Commitments

In accordance with the terms of the Support Structures Purchase Agreement, the final amount of $4,044,000 required to complete the purchase of all joint-use poles within Newfoundland Power's service territory from Aliant Telecom Inc. will be paid in 2005.

Project Title: **Rebuild Distribution Lines**

Location: **Various**

Classification: **Distribution**

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

Project Description

This project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through ongoing line inspections, engineering reviews, or day to day operations. The total budget estimate for this category is based on individual estimates.

Distribution rebuild projects can involve either the complete rebuilding of deteriorated distribution lines or the selective replacement of various line components based on inspections and engineering reviews. These typically include the replacement of poles, crossarm, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

The work for 2004 includes feeder improvements on approximately 56 of the Company's 300 feeders, upgrades to feeders KBR-05 and SLA-06 in St. John's, replacement of deteriorated padmount transformers and underground services, installation of support for cable termination on Bell Island, upgrades to secondary circuits in Grand Bank/Fortune and work estimated to cost less than $50,000 at a number of other locations. Details are contained in Volume III, Distribution, Appendix 2.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$1,696	-	-	-
Labour – Internal	1,512	-	-	-
Labour – Contract	492	-	-	-
Engineering	103	-	-	-
Other	334	-	-	-
Total	**$4,137**	**$4,051**	**$15,246**	**$23,434**

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$1,598	$755	$2,223	$3,210	$3,449

Operating Experience

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards on a five-year rotation to identify:

a) Deficiencies with plant that are a risk to Public Safety, Employee Safety, or are likely to result in Imminent Failure of a structure or hardware.
b) Transformers containing PCB that need to be replaced.
c) Transformers that must be replaced due to rust.
d) Locations where lightning arrestors are required as per the 2003 Lightning Arrestor Review. See Volume III, Distribution, Appendix 2, Attachment B.
e) Locations where CP8080 and 2-piece insulators still exist. These insulators have a history of failure. See Volume III, Distribution, Appendix 2, Attachment C.
f) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000. See Volume III, Distribution, Appendix 2, Attachment D.
g) Hardware that has high risk of failure, such as automatic sleeves and porcelain cutouts. See Volume III, Distribution, Appendix 2, Attachment E and Attachment F.

In addition to items identified during regularly scheduled inspections noted above, specific engineering reviews and the day to day operations of the Company also identify plant deficiencies that need to be addressed within the capital expenditure program.

Project Justification

The Company has over 8,000 kilometers of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important part of meeting this obligation.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Relocate/Replace Distribution Lines for Third Parties**

Location: **Various**

Classification: **Distribution**

Project Cost: **$235,000**

Project Description

This project is necessary to accommodate third party requests for the relocation or replacement of distribution lines. The relocation or replacement of distribution lines results from (1) work initiated by municipal, provincial and federal governments, (2) work initiated by other utilities such as Aliant Telecom and Rogers Cable, (3) requests from customers or (4) vehicle accident damage.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$78	-	-	-
Labour – Internal	86	-	-	-
Labour – Contract	60	-	-	-
Engineering	8	-	-	-
Other	3	-	-	-
Total	**$235**	**$235**	**$705**	**$1,175**

Operating Experience

The cost estimate is based on historical expenditures and some individual project estimates. Generally these expenditures are associated with a number of small projects that are not specifically identified at the time the budget is prepared.

The following table shows the annual expenditures for the past five years.

Project Cost

Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$596	$769	$585	$390	$293

Project Justification

The Company must respond to requests for relocation and replacement of distribution facilities under the provisions of agreements in place with the requesting parties.

Estimated contributions from customers and requesting parties associated with this project have been included in the $1.5 million contribution in aid of construction amount referred to in the Application.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Distribution Reliability Initiative**

Location: **Various**

Classification: **Distribution**

Project Cost: **$949,000**

Project Description

The project involves the upgrading or addition of trunk feeder structures and equipment to reduce both the frequency and duration of power interruptions to the customers served by the distribution line. The nature of the upgrading work follows from a detailed assessment of past problems, knowledge of local environmental conditions (such as salt contamination and wind and ice loading), and engineering knowledge to apply location specific design and construction standards. Project plans are subsequently developed from an engineering analysis and options are evaluated that improve reliability performance.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$423	-	-	-
Labour – Internal	338	-	-	-
Labour – Contract	98	-	-	-
Engineering	12	-	-	-
Other	78	-	-	-
Total	**$949**	**$1,315**	**$2,400**	**$4,664**

Operating Experience

The following table identifies the feeders selected for upgrading in 2004 and indicates the number of customers affected, and the average unscheduled yearly interruption statistics for the five-year period ending December 31, 2002. The SAIFI and SAIDI statistics exclude planned power interruptions and interruptions due to loss of supply from Hydro. See Volume III, Distribution, Appendix 3, Attachment A for an analysis of WES-02 and Appendix 3, Attachment B for an analysis of BRB-04 and Appendix 3, Attachment C for an analysis of PUL-01 and PUL-02.

Feeder	Number of Customers	SAIFI[1] Interruptions Per Year	SAIDI[2] Hours Per Year
Lumsden/Cape Freels (WES-02)	766	3.7	6.3
Bay Roberts/Port Au Grave (BRB-04)	1,013	1.5	5.5
Torbay (PUL-01)	1,935	1.8	3.8
Flatrock/Pouch Cove (PUL-02)	1,427	2.8	5.0
Company Average		1.8	2.9

Notes:

[1] System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

[2] System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

The following table shows the expenditures for this project for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$2,870	$1,776	$3,422	$1,092	$1,247

Project Justification

These projects are justified on the basis of reliability improvement. Customers currently supplied by these feeders experience power interruptions more often or of longer duration than the Company average. Individual feeder projects have been prioritized based on their historic SAIFI and SAIDI statistics.

Expenditures on the distribution reliability initiative have had a positive impact on the reliability performance of the feeders that have been upgraded.

The total WES-02 project is estimated at $1,099,000, of which $699,000 will be expended in 2004, and will require approximately $400,000 in 2005 to complete that item.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

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

Location: **Chamberlains, Glendale and Springfield**

Classification: **Distribution**

Project Cost: **$677,000**

Project Description

This project consists of the construction of a new feeder, equipment or conductor upgrades on existing feeders and/or installation of sections of feeders to accommodate energy sales growth.

The work for 2004 includes the construction of a new feeder at Chamberlains, reconductoring a section of Glendale-01 feeder and the installation of voltage regulators on Springfield-01 feeder.

**Project Cost
(000s)**

Cost Category	2004	2005	2006 - 2008	Total
Material	$216	-	-	-
Labour – Internal	204	-	-	-
Labour – Contract	213	-	-	-
Engineering	25	-	-	-
Other	19	-	-	-
Total	**$677**	**$230**	**$700**	**$1,607**

Operating Experience

Forecast and actual peak load conditions and customer growth indicate that these projects are warranted in order to maintain the electrical system within recommended guidelines. See Volume III, Distribution, Appendix 4 for more details.

The following table shows the expenditures for the past five years.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$37	$262	$0	$0	$0

Project Justification

This project is required to maintain substation transformer loading, voltage regulation and/or customer loading density within recommended guidelines.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Switch Replacement and Upgrade Underground Distribution Water St., St. John's**

Location: **St. John's**

Classification: **Distribution**

Project Cost: **$750,000**

Project Description

This project is the completion of a project started in 2000. It involves the replacement and upgrade of high voltage oil-filled switches, platform-mounted transformers and high voltage distribution vaults that form part of the Water Street underground distribution system. The project will require the installation of pad-mount switches and pad-mount transformers, as well as the establishment of loop feeds for sections of the underground distribution system at various locations along Water Street, St. John's.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$361	-	-	$361
Labour – Internal	288	-	-	288
Labour – Contract	90	-	-	90
Engineering	9	-	-	9
Other	2	-	-	2
Total	**$750**	**$0**	**$0**	**$750**

Operating Experience

Commercial properties in the Water Street area of the downtown core of St. John's are served by an underground distribution system installed in the mid-1960s. The plant and equipment that form this system have reached the end of their expected lives. In addition, the underground switches that permit sectionalizing and isolation of various portions of this system are a recognized safety hazard and are no longer supported by the manufacturer. There are several locations where 30-year-old aerial transformer bank structures are located next to buildings resulting in safety clearance problems for workers maintaining these buildings. There are also a number of high voltage electrical vaults that require attention to barricade bare conductors and equipment to protect persons entering these locations.

In 2000, a program of replacement or elimination of the thirteen underground switches was initated. To the end of 2002, seven of these switches had been replaced or eliminated. An additional 5 switches will be replaced or eliminated as part of the 2003 capital project. In 2004, the last remaining oil-filled switch (in manhole #6) will be replaced and upgrading of 6 underground vaults will be completed to address safety concerns.

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$0	$77	$279	$469	$765

Project Justification

The remaining high voltage oil-filled switch is over 30 years old and the manufacturer states that they cannot guarantee that the switch has load break capability. The manufacturer no longer supplies replacement parts for this switch. As well, there are safety issues associated with certain operations of the existing switch. For example, the switch relies on manual operation, and internal arcing and deterioration of contacts may occur. New switches have technology that eliminates these safety concerns.

In conjunction with the switch replacement, there are other areas along the Water Street distribution system that require attention. For example, there are several locations where transformers are located on platforms that are 30 years old and are located next to buildings, resulting in clearance problems for workers engaged in maintaining the exterior of these buildings.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Interest During Construction**

Location: **N/A**

Classification: **Distribution**

Project Cost: **$100,000**

Project Description

This is an estimate of the interest during construction that will be charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months.

Operating Experience

This calculation is based on an estimated monthly average of total distribution work in progress of $1.0 million. The interest rate which is applied each month is dependent on the source of funds to finance the capital expenditure and is calculated in accordance with Order No. P.U. 37 (1981).

The following table shows the expenditures for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$93	$83	$78	$80	$100

Project Justification

These costs are justified on the same basis as the distribution work orders to which they are charged.

Future Commitments

None.

GENERAL PROPERTY

Project Title: **Tools & Equipment**

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

Classification: **General Property**

Project Cost: **$535,000**

Project Description

This project is the addition or replacement of tools and equipment utilized by line and support staff in the day-to-day operations of the Company, as well as the replacement or addition of office furniture and equipment. Details of equipment to be acquired in 2004 are contained in Volume III, General Property, Appendix 1.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$535	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$535**	**$518**	**$1,125**	**$2,178**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$798	$427	$537	$378	$827

Project Justification

This equipment enables staff to perform work in a safe, effective and efficient manner.

The project cost is based on historical costs for the replacement of tools and equipment that become broken or worn out. Additional or replacement tools are purchased to increase employee productivity, quality of work and overall operational efficiency.

Future Commitments

None.

Project Title: **Real Property**

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

Classification: **General Property**

Project Cost: **$174,000**

Project Description

This project is the addition to, or renovation of, Company buildings and property that are not part of the electrical supply to customers. Details of work associated with each location noted above are contained in Volume III, General Property, Appendix 2.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$169	-	-	-
Labour – Internal	2	-	-	-
Labour – Contract	-	-	-	-
Engineering	3	-	-	-
Other	-	-	-	-
Total	**$174**	**$662**	**$1,848**	**$2,684**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$1,500	$503	$407	$337	$220

Project Justification

The project is necessary to maintain buildings and support facilities and to operate them in an efficient manner

Future Commitments

None.

TRANSPORTATION

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

Location: **Various**

Classification: **Transportation**

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

Project Description

This project involves the necessary replacement of passenger vehicles and aerial devices (line trucks). The Company has determined that the units to be replaced have reached the end of their useful lives.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$3,433	-	-	-
Labour – Internal	45	-	-	-
Labour – Contract		-	-	-
Engineering	9	-	-	-
Other		-	-	-
Total	**$3,487**	**$2,831**	**$7,045**	**$13,363**

The following table lists units to be acquired in 2004.

Category	**No. of Units**
Passenger/off-road vehicles [1]	15
Heavy fleet vehicles [2]	12
Off –road vehicles [3]	9
Total	**36**

Notes:

[1] The Passenger/Off-Road Vehicles category includes the purchase of cars and light duty trucks.
[2] The Heavy Fleet Vehicles category includes the purchase of replacement line trucks.
[3] The off-road category includes snowmobiles, ATVs and trailers.

Operating Experience

Volume III, Transportation, Appendix 1 provides information with respect to age, odometer reading and maintenance cost for each vehicle selected for replacement.

The following table gives the expenditures for the past five years for this project.

Project Cost

Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$1,797	$2,276	$2,061	$1,609	$3,076

Project Justification

The company has a guideline that initiates the replacement of vehicles. For passenger vehicles the guideline is age of five years or 150,000 kilometers. For heavy fleet vehicles the guideline is age of 10 years or 250,000 kilometers.

All units to be replaced have been evaluated for factors such as overall condition, maintenance history and immediate repair requirements. Based on this evaluation, it has been determined that each unit has reached the end of its useful life.

New vehicles are acquired through competitive tendering and lease/buy analyses are prepared to ensure the lowest possible cost consistent with reliable service.

Future Commitments

None.

TELECOMMUNICATIONS

Project Title: **Replace/Upgrade Communication Equipment**

Location: **Various**

Classification: **Telecommunications**

Project Cost: **$70,000**

Project Description

This project involves the replacement and/or upgrade of equipment identified during inspections or during day to day operations.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$59	-	-	-
Labour – Internal	7	-	-	-
Labour – Contract	-	-	-	-
Engineering	4	-	-	-
Other	-	-	-	-
Total	**$70**	**$70**	**$281**	**$421**

Operating Experience

Older vintage radio equipment and towers are susceptible to breakdown and other deficiencies. Where practical, equipment is repaired and deficiencies rectified, however, where it is not feasible to repair the equipment or correct the deficiencies, new units are acquired.

The following table gives the expenditures for the past five years for this project.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$113	$125	$94	$105	$205

Project Justification

Newfoundland Power engages an engineering consultant to inspect radio towers. Deficiencies identified through these inspections are addressed through this project. The Company has

approximately 340 mobile radios in service. Each year approximately 20 units that show a high frequency of breakdown and repair are identified and replaced with more reliable units.
The Company will ensure this project is completed at the lowest possible cost consistent with reliable service.

Future Commitments

None.

Project Title: **Substation Telephone Circuit Protection**

Location: **Deer Lake, Riverhead, Tors Cove, Salt Pond and Trepassey**

Classification: **Telecommunications**

Project Cost: **$50,000**

Project Description

This project involves upgrades to teleline isolation installations at Deer Lake, Riverhead, Tors Cove, Salt Pond and Trepassey substations.

Project Cost (000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$18	-	-	-
Labour – Internal	17	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	-	-	-	-
Total	**$50**	**$90**	**$297**	**$437**

Operating Experience

This work will assist in ensuring all personnel using or working on the communication equipment at each of these substations, and at the telephone exchanges serving the substations, will be protected from electrical shock caused by excessive ground potential rise. It will also eliminate the possibility that ground potential rise may damage communications equipment of third parties sharing cable plant with Newfoundland Power equipment.

The following table gives the expenditures for the past five years for this project.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$167	$208	$25	$0	$89

Project Justification

This project is justified on the basis of safety and reliability. Teleline isolation equipment will ensure that Aliant Telecom equipment remote from each substation will also be protected from any ground potential rise. The use of teleline isolation also ensures that the Company's SCADA communications circuits remain available to control and monitor the electrical system. This communication is necessary to ensure the safe and reliable management of power system devices.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering, except in the case of teleline isolation equipment where Aliant Telecom Inc. is the sole supplier.

Future Commitments

None.

INFORMATION SYSTEMS

Project Title: **Application Enhancements**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$1,355,000**

Project Description

The Company has software applications that are custom developed, such as the Customer Service System ("CSS"), and others that are vendor provided such as Microsoft Great Plains. This project is necessary to enhance these software applications to support changing business requirements and to take advantage of new development and product improvements. For details, see Volume IV, Information Systems, Appendix 1.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$ 23	-	-	-
Labour – Internal	735	-	-	-
Labour – Contract		-	-	-
Engineering		-	-	-
Other	597	-	-	-
Total	**$1,355**	**$1,390**	**$3,400**	**$6,145**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$555	$906	$619	$726	$836

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

None.

Project Title: **Application Environment**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$791,000**

Project Description

This project involves the necessary upgrading of technology products and related processes required to support the implementation, upgrading, and enhancement of the Company's computer applications. It includes upgrades to current software tools, processes and applications as well as the acquisition of new software licences. For details see Volume IV, Information Systems, Appendix 2.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$270	-	-	-
Labour – Internal	346	-	-	-
Labour – Contract		-	-	-
Engineering		-	-	-
Other	175	-	-	-
Total	**$791**	**$410**	**$2,620**	**$3,821**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$1,724	$587	$560	$724	$846

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

None.

Project Title: **Customer Systems Replacement**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$226,000**

Project Description

This project involves customer service and efficiency enhancements to the Customer Service System which also will reduce reliance on the OpenVMS operating system. This includes improvements to the customer bill formatting and printing procedure which currently is a difficult and costly process. For details see Volume IV, Information Systems, Appendix 3.

Project Cost (000s)				
Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$15	-	-	-
Labour – Internal	166	-	-	-
Labour – Contract		-	-	-
Engineering		-	-	-
Other	45	-	-	-
Total	**$226**	**$250**	**$520**	**$996**

Operating Experience

The following table gives the expenditures for this project for the past year.

Project Cost					
Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$0	$0	$0	$0	$170

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

None.

Project Title: **Network Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$393,000**

Project Description

This is the second year of a two-year project involving the replacement of aging network components that no longer support the business needs of the Company or are no longer supported by the vendor. For details see Volume IV, Information Systems, Appendix 4.

Project Cost
(000s)

Cost Category	**2004**	**2005**	**2006 - 2008**	**Total**
Material	$341	-	-	-
Labour – Internal	36	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	16	-	-	-
Total	**$393**	**$250**	**$150**	**$793**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost

Year	**1999**	**2000**	**2001**	**2002**	**2003F**
($000s)	$237	$205	$0	$0	$547

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

A stable and effective network is critical to ensuring the availability of the Company's business applications to enable employees to be more responsive to customers. The network components being replaced connect the Company's offices across the province to the St. John's offices and is used by employees to access applications like the Customer Service System, Problem Call Logging System, Safety applications, engineering design applications, email, Business Support Systems, Intranet, etc. The new network components will provide the additional network capacity and performance required for the delivery of these business applications. As well, it will reduce the Company's reliance on technology that is no longer manufactured.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

None.

Project Title: **Personal Computer Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$539,000**

Project Description

This project is necessary for the replacement or upgrade of personal computers, printers and associated assets that have reached the end of their useful life. The Company currently has an expectation of a four to five year life cycle for personal computers. In 2004 109 PCs will be replaced (74 desktop computers and 35 laptop computers). This project also covers the purchase of 4 printers to replace existing printers that have reached the end of their useful life and additional peripheral equipment such as monitors.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$368	-	-	-
Labour – Internal	72	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	99	-	-	-
Total	**$539**	**$550**	**$1,655**	**$2,744**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$1,242	$784	$405	$635	$564

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

The Company annually reviews its personal computing requirements in detail as a part of its capital budgeting process to ensure that each employee has the computing power necessary to perform their job effectively. The objective of this project is to accommodate application enhancements and new applications while maintaining current performance standards and customer service levels. As well, the replacement of personal computer infrastructure and the reassignment of older, less powerful personal computers to users with lesser capacity requirements will extend the useful life of personal computers.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

None.

Project Title: **Shared Server Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$644,000**

Project Description

The Shared Server Infrastructure project includes the procurement, implementation, and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

This project is necessary to maintain current performance on the Company's shared servers and to provide the additional infrastructure needed to accommodate new and existing applications. This involves the replacement and upgrade of disks, processors, and memory, as well as security and monitoring software. For details see Volume IV, Information Systems, Appendix 5.

Project Cost
(000s)

Cost Category	2004	2005	2006 - 2008	Total
Material	$414	-	-	-
Labour – Internal	145	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	85	-	-	-
Total	**$644**	**$900**	**$2,350**	**$3894**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost

Year	1999	2000	2001	2002	2003F
($000s)	$160	$286	$625	$705	$1,561

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

This project is justified on the basis of the need to provide additional capacity to support new applications and to maintain the performance of the Company's servers. Some of the Company's major shared servers are used by as many as 400 employees at one time. Degradation of server performance can have a negative impact on employee productivity, customer service, and the integrity of stored corporate data.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

None.

UNFORESEEN ITEMS

Project Title: **Allowance for Unforeseen Items**

Location: **Various**

Classification: **Unforeseen Items**

Project Cost: **$750,000**

Project Description

This allowance is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damages or equipment failure.

Operating Experience

This project provides funds for timely service restoration.

Project Justification

Projects for which these funds are intended are justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitment

None.

Newfoundland Power Inc.
2004 Capital Budget
Estimate of Future Required Expenditures on 2004 Projects
(000s)

Budget Class and Project	**2004**	**2005**
Distribution		
Aliant Pole Purchase	$4,044	$4,044

Newfoundland Power Inc.
2004 Capital Budget

2002 Rate Base
(000s)

	2001	2002
Plant Investment	$971,294	$1,005,674
Deduct:		
Accumulated Depreciation	408,167	420,736
Contributions in Aid of Construction	19,986	19,788
Deferred Income Taxes	-	-
Weather Normalization Reserve	(9,900)	(10,919)
	418,253	429,605
	553,041	576,069
Add – Contributions Country Homes	545	570
Balance – Current Year	553,586	576,639
Balance – Previous Year	520,475	553,586
Average	537,031	565,113
Cash Working Capital Allowance	4,561	4,712
Materials and Supplies	3,570	3,512
Average Rate Base at Year End	545,162[1]	573,337

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[1] Approved per Order No. P.U. 36 (2002-2003).

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

2003 Capital Expenditure Status Report

NEWFOUNDLAND POWER
A FORTIS COMPANY

NEWFOUNDLAND POWER INC.

2004 CAPITAL BUDGET APPLICATION

2003 Capital Expenditure Status Report

Explanatory Note

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities contained in paragraph 6 of Order No. P.U. 36 (2002-2003).

Variances of more than 10% of approved expenditure or $50,000 or greater are explained in the Notes contained in Appendix A, which immediately follows the blue page at the conclusion of the 2003 Capital Expenditure Status Report.

Newfoundland Power Inc.
2004 Capital Budget

2003 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 36 (2002-2003), P.U. 19 (2003)	Forecast	Variance
Energy Supply	$7,076	$7,429[1]	353
Substations	5,887	5,820[3]	(67) [3]
Transmission	4,129	4,291[2]	162
Distribution	26,132	27,614[3]	1,482[3]
General Property	910	1,047	137
Transportation	2,141	2,328	187
Telecommunications	383	294	(89)
Information Systems	5,507	5,728	221
General Expenses Capital	2,800	2,800	0
Unforeseen	750	375	(375)
Total	55,715	57,726	2,011
Projects carried forward from 2002	-	5,528	

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[1] Includes capital expenditures of $19,000 incurred in 2002.

[2] Includes capital expenditures of $50,000 incurred in 2002.

[3] On June 27, 2003, Newfoundland Power submitted a Supplementary Application to the Board seeking approval of a project in the amount of $721,000, which affects the substations and distribution categories. The amounts of $271,000 allocated to Substations and $450,000 allocated to Distribution are contained in the Forecast column with corresponding amounts in the Variance column.

2003 Capital Expenditure Status Report
(000s)

	Capital Budget 2003	Actual Expenditures			Forecast			Variance
		2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	
2003 Capital Projects	$ 52,915	$ 69	$ 19,404	$ 19,923	$ 35,003	$ 54,140	54,926	$ 2,011
2003 General Expenses Capital	2,800	-	1,408	1,408	1,392	2,800	2,800	$ -
Grand Total	$ 55,715	$ 69	$ 20,812	$ 21,331	$ 36,395	$ 56,940	$ 57,726	$ 2,011

2002 Capital Expenditure Carryover Report
(000s)

	Capital Budget 2002	Capital Budget 2003	Actual Expenditures 2002	Actual Expenditures YTD 2003	Actual Expenditures Total To Date	Forecast Remainder of 2003	Forecast Total 2003	Forecast Overall Total	Variance
2002 Projects Carried into 2003	15,046		11,007	1,388	12,395	4,140	5,528	16,535	1,489
Grand Total	$ 15,046	$ -	$ 11,007	$ 1,388	$ 12,395	$ 4,140	$ 5,528	$ 16,535	$ 1,489

2003 Capital Expenditure Status Report
(000s)

Class: Energy Supply

	Capital	Capital		Actual Expenditures			Forecast				
Project	Budget 2002	Budget 2003	Total	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Hydro Plants - Facility Rehabilitation	$ -	$ 2,345	$ 2,345	$ -	$ 222	$ 222	$ 2,158	$ 2,380	$ 2,380	$ 35	
Thermal Plants - Facility Rehabilitation	-	1,561	1,561	14	72	86	1,687	1,759	1,773	212	1
Purchase Portable Diesel Generation	-	1,500	1,500	-	17	17	1,583	1,600	1,600	100	2
Penstock Replacement - Lockston	-	1,520	1,520	5	33	38	1,488	1,521	1,526	6	
Major Electrical Equipment Repairs	-	150	150	-	3	3	147	150	150	-	
	-	7,076	7,076	19	347	366	7,063	7,410	7,429	353	
<u>Carry Overs</u>											
Wesleyville Gas Turbine Replacement	$ 1,674		$ 1,674	$ 1,356	$ 53	$ 1,409	$ 675	$ 728	$ 2,084	$ 410	3
Hydro Plants - Facility Rehabilitation	1,771		1,771	2,031	336	2,367	62	398	2,429	658	4
Thermal Plants - Facility Rehabilitation	828		828	656	95	751	309	404	1,060	232	5
System Control Centre - Extend SCADA Capabilities	-		-	29	35	64	40	75	104	104	6
Gas Turbine - Replace Governor and Control Logic	500		500	317	80	397	80	160	477	(23)	
	4,773		4,773	4,389	599	4,988	1,166	1,765	6,154	1,381	
Total	$ 4,773	$ 7,076	$ 11,849	$ 4,408	$ 946	$ 5,354	$ 8,229	$ 9,175	$ 13,583	$ 1,734	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Substations

Project	Capital Budget 2002	Capital Budget 2003	Total	Actual Expenditures 2002	Actual Expenditures YTD 2003	Actual Expenditures Total To Date	Forecast Remainder of 2003	Forecast Total 2003	Forecast Overall Total	Variance	Notes*
Rebuild Substations	$ -	$ 557	$ 557	$ -	$ 73	$ 73	$ 379	$ 452	$ 452	$ (105)	7
Replacement and Spare Substation Equipment	-	1,107	1,107	-	220	220	850	1,070	1,070	(37)	
Reliability and Power Quality Improvements	-	198	198	-	9	9	109	118	118	(80)	8
Substation Protection and Monitoring Improvements	-	425	425	-	44	44	386	430	430	5	
Distribution System - Feeder Remote Control	-	1,200	1,200	-	540	540	660	1,200	1,200	-	
Virginia Waters - Add 66/12.5kV Transformer	-	1,150	1,150	-	32	32	1,016	1,048	1,048	(102)	9
Chamberlains - Add 66/25 kV Transformer		1,250	1,250		53	53	1,182	1,235	1,235	(15)	
Customer Growth - Cow Head		-	-		9	9	258	267	267	267	10
	-	5,887	5,887	-	980	980	4,840	5,820	5,820	(67)	
Carry Overs											
Purchase Power Transformer	$ 2,000		$ 2,000	48	95	143	1,610	1,705	1,753	(247)	11
St. John's Area Transmission Relaying Improvement Program	593		593	513	130	643	144	274	787	194	12
Modifications to Accommodate Gas Turbine	480		480	719	49	768	56	105	824	344	13
Replacement and Spare Substation Equipment	2,475		2,475	2,716	100	2,816	36	136	2,852	377	14
	5,548		5,548	3,996	374	4,370	1,846	2,220	6,216	668	
Total	$ 5,548	$ 5,887	$ 11,435	$ 3,996	$ 1,354	$ 5,350	$ 6,686	$ 8,040	$ 12,036	$ 601	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Transmission

	Capital	Actual Expenditures			Forecast				
Project	Budget 2003	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Rebuild Transmission Lines	$ 4,129	$ 50	$ 1,415	$ 1,465	$ 2,826	$ 4,241	$ 4,291	$ 162	15
		-		-	-		-	-	
Total	$ 4,129	$ 50	$ 1,415	$ 1,465	$ 2,826	$ 4,241	$ 4,291	$ 162	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Distribution

	Capital	Actual Expenditures			Forecast				
Project	Budget 2003	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Extensions	$ 4,322	$ -	$ 2,509	$ 2,509	$ 2,225	$ 4,734	$ 4,734	$ 412	16
Meters	674	-	280	280	394	674	674	-	
Services	1,819	-	635	635	1,206	1,841	1,841	22	
Street Lighting	952	-	442	442	791	1,233	1,233	281	17
Transformers	4,975	-	2,710	2,710	2,185	4,895	4,895	(80)	18
Reconstruction	2,745	-	1,328	1,328	1,417	2,745	2,745	-	
Aliant Pole Purchase	4,044	-	4,044	4,044	-	4,044	4,044	-	
Load Research	425		3	3	422	425	425		
Trunk Feeders									
Rebuild Distribution Lines	3,504	-	1,270	1,270	2,179	3,449	3,449	(55)	19
Relocate/Replace Distribution Lines For Third Parties	275	-	74	74	219	293	293	18	
Distribution Reliability Initiative	1,078	-	238	238	1,009	1,247	1,247	169	20
Improve Distribution System Protection/Operation	457	-	300	300	419	719	719	262	21
Replace Underground Switches - Water Street, St. John's	762	-	124	124	641	765	765	3	
Extensions-Cow Head	-	-	450	450	-	450	450	450	22
Interest During Construction	100	-	24	24	76	100	100	-	
Total	$ 26,132	$ -	$ 14,431	$ 14,431	$ 13,183	$ 27,614	$ 27,614	$ 1,482	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: General Property

	Capital	Actual Expenditures			Forecast				
Project	Budget 2003	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Tools and Equipment	$ 770	$ -	$ 364	$ 364	$ 463	$ 827	$ 827	$ 57	23
Additions to Real Property	140	-	115	115	105	220	220	80	24
Total	$ 910	$ -	$ 479	$ 479	$ 568	$ 1,047	$ 1,047	$ 137	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Transportation

	Capital	Capital		Actual Expenditures			Forecast				
Project	Budget 2002	Budget 2003	Total	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Purchase of Vehicles and Aerial Devices		$ 2,141	$ 2,141	$ -	$ 523	$ 523	$ 1,805	$ 2,328	$ 2,328	$ 187	25
<u>Carry Overs</u>											
Purchase of Vehicles and Aerial Devices	$ 2,200		2,200	1,609	-	$ 1,609	748	748	$ 2,357	157	26
Total	$ 2,200	$ 2,141	$ 4,341	$ 1,609	$ 523	$ 2,132	$ 2,553	$ 3,076	$ 4,685	$ 344	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Telecommunications

Project	Capital Budget 2002	Capital Budget 2003	Total	Actual Expenditures 2002	Actual Expenditures YTD 2003	Actual Expenditures Total To Date	Forecast Remainder of 2003	Forecast Total 2003	Forecast Overall Total	Variance	Notes*
Replace/Upgrade Communications Equipment	$ -	$ 242	$ 242	$ -	$ -	$ -	$ 205	$ 205	$ 205	$ (37)	27
Substation Telephone Circuit Protection	-	141	141	-	3	3	86	89	89	(52)	28
	-	383	383	-	3	3	291	294	294	(89)	
Carry Overs											
Fibre Optic Networking	$ 264		264	115	139	254	(15)	124	239	(25)	
Total	$ 264	$ 383	$ 647	$ 115	$ 142	$ 257	$ 276	$ 418	$ 533	$ (114)	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Information Systems

	Capital	Capital		Actual Expenditures			Forecast				
Project	Budget 2002	Budget 2003	Total	2002	YTD 2003	Total To Date	Remainder of 2003	Total 2003	Overall Total	Variance	Notes*
Application Enhancements	$ -	$ 766	$ 766	$ -	$ 413	$ 413	$ 423	$ 836	$ 836	$ 70	29
Application Environment	-	755	755		84	84	762	846	846	91	30
Customer Service System Study		170	170		69	69	101	170	170		
Facilities Management	-	562	562		298	298	255	553	553	(9)	
Network Infrastructure		542	542		16	16	531	547	547	5	
Operations Support Systems	-	383	383		130	130	241	371	371	(12)	
Outage Management	-	284	284	-	7	7	273	280	280	(4)	
Personal Computer Infastructure		634	634	-	69	69	495	564	564	(70)	31
Shared Servers Infastructure		1,411	1,411	-	590	590	971	1,561	1,561	150	32
		5,507	5,507	-	1,676	1,676	4,052	5,728	5,728	221	
Carry Overs											
Operations Support Systems	$ 1,322		$ 1,322	459	61	520	245	306	765	(557)	33
Facilities Management	939		939	439	215	654	150	365	804	(135)	34
	2,261	-	2,261	898	276	1,174	395	671	1,569	(692)	
Total	$ 2,261	$ 5,507	$ 7,768	$ 898	$ 1,952	$ 2,850	$ 4,447	$ 6,399	$ 7,297	$ (471)	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
(000s)

Class: Unforeseen Items

Project	Capital Budget 2003	Actual Expenditures 2002	Actual Expenditures YTD 2003	Actual Expenditures Total To Date	Forecast Remainder of 2003	Forecast Total 2003	Forecast Overall Total	Variance	Notes*
Allowance for Unforseen Items	$ 750	$ -	$ -	$ -	$ 375	$ 375	$ 375	$ (375)	35
		-		-	-		-	-	
Total	$ 750	$ -	$ -	$ -	$ 375	$ 375	$ 375	$ (375)	

* See Appendix A for notes containing variance explanations.

2003 Capital Expenditure Status Report
Notes

Energy Supply

1. *Thermal Plants - Facility Rehabilitation:*
   Budget: $1,561,000 Forecast: $1,773,000 Variance: $212,000

   The original project for the mobile gas turbine at Port aux Basques involved refurbishment of the protection, controls and housing. However, further analysis identified the need to expand the project to include refurbishment of the gas generator ($325,000). This was somewhat offset by a lower than expected contract price for the installation of an exhaust stack at the Greenhill gas turbine (-$123,000).

2. *Purchase Portable Diesel Generation:*
   Budget: $1,500,000 Forecast: $1,600,000 Variance: $100,000

   Contract prices received following the tender call were higher than had been anticipated ($100,000).

3. *Wesleyville Gas Turbine Relocation (2002 Project):*
   Budget: $1,674,000 Forecast: $2,084,000 Variance: $410,000

   The increase in this project is the result of two items. First, as a result of the discussions with the manufacturer and other engineering firms, it was determined that certain original, 30 year old, items would be compromised during relocation and should be replaced ($120,000); second, additional interest was incurred during construction ($96,000); and third, additional engineering, project management and commissioning costs were incurred ($150,000) mainly as a result of deferring the relocation from 2002 to 2003.

4. *Hydro Plants – Facility Rehabilitation (2002 Project):*
   Budget: $1,771,000 Forecast: $2,429,000 Variance: $658,000

   The increase in this category is the result of the Company’s decision to replace the governor and the control system for both generating units at the Seal Cove Hydroelectric plant rather than only one unit as planned in the original budget. This decision was made when an equipment failure in the second unit in March of 2002 caused significant damage to the generator. Due to the fact that it was necessary to rebuild the second generator, it was determined to be prudent to also replace the governor and the control system at the same time. The increase in costs for the Seal Cove project were somewhat offset by the deferral until 2003 of similar work at Tors Cove and Topsail Hydroelectric plants.

2003 Capital Expenditure Status Report
Notes

Energy Supply

5. *Thermal Plants – Facility Relocation (2002 Project):*
   Budget: $828,000 Forecast: $1,060,000 Variance: $232,000

   The increase in this project is a result of increase costs associated with the Greenhill Gas Turbine upgrade ($129,000) and the Salt Pond Gas Turbine air intake replacement ($60,000).

   During the implementation of the upgrades at the Greenhill Gas Turbine, problems were experienced with the vibration monitoring system. The system was obsolete and replacement parts unavailable, resulting in a requirement to replace the whole system.

   The original plan for the replacement of the Salt Pond air intake structure anticipated that the inlet plenum would be reused. However, on further inspection by a third party consultant, it will be determined that, due to age and deterioration, the structural integrity would be compromised during relocation and should be replaced.

6. *Web Enterprise Upgrade SCADA (2001 Project):*
   Budget: $0 Forecast: $104,000 Variance: $104,000

   This project was a carryover from the 2001 budget and is designed to provide web-based access to screens and telemetry available through SCADA. It will be completed in 2003.

2003 Capital Expenditure Status Report
Notes

Substations

7. *Rebuild Substations:*
Budget: $557,000 Forecast: $452,000 Variance: -$105,000

An engineering analysis of projects to upgrade substations at Grand Beach and Trepassey revealed that the work required was in excess of the original estimate. As a result, both of these projects were scaled back such that $35,000 will be spent to complete engineering and drafting this year (-$87,000). In addition, planned work to extend safety clearances around certain regulators was deferred pending further engineering analysis (-$36,000). These reductions were somewhat offset by the unplanned replacement of a breaker at Laurentian substation following an equipment failure ($18,000).

8. *Reliability and Power Quality Improvements:*
Budget: $198,000 Forecast: $118,000 Variance: -$80,000

The transmission line switch program on 39L was reduced to include engineering only in order to release resources for other higher priority projects (-$82,000). This will be carried forward into 2004.

9. *Virginia Waters – Add 66/12.5kv Transformer:*
Budget: $1,150,000 Forecast: $1,048,000 Variance: -$102,000

The contract prices received following the tender call were lower than had been anticipated (-$102,000).

10. *Customer Growth – Cow Head*
Budget: $0 Forecast: $267,000 Variance: $267,000

This is a customer driven project that was not anticipated when the 2003 Capital Budget was prepared.

11. *Purchase Power Transformer (2002 Project):*
Budget: $2,000,000 Forecast: $1,753,000 Variance: -$247,000

The contract prices received following the tender call were lower than had been anticipated (-$247,000).

2003 Capital Expenditure Status Report
Notes

Substations

12. *St. John's Area & Transmission Relaying Improvement Program (2002 Project):*
    Budget: $593,000 Forecast: $787,000 Variance: $194,000

    Due to the complexity and communication incompatibility of some of the hardware components, identified during the implementation phase of the project, additional communications interface devices were required ($194,000).

13. *Modification to Accommodate Gas Turbine (2002 Project):*
    Budget: $480,000 Forecast: $824,000 Variance: $344,000

    The variance in this project reflects the cost of an additional high voltage breaker, the construction of a steel structure, the relocation of a transformer and the addition of a battery bank and charging system ($344,000). These items were added to meet substation standards.

14. *Replacement and Spare Substation Equipment (2002 Project):*
    Budget: $2,475,000 Forecast: $2,852,000 Variance: $377,000

    The increase in this category is primarily attributable to the repair of the 1966-vintage T1 transformer at Grand Bay Substation, which failed in December 2001 ($207,000), the unplanned replacement of voltage regulator panels that failed during 2002 ($50,000), and increased costs to repair portable substation P-435, ($25,000).

2003 Capital Expenditure Status Report
Notes

Transmission

15. *Rebuild Transmission Lines:*
    Budget: $4,129,000   Forecast: $4,291,000   Variance: $162,000

    The variance is the result of high priority projects identified during the 2003 transmission line inspections ($100,000), along with increased survey costs on 100L, 124L and 146L ($59,000).

2003 Capital Expenditure Status Report
Notes

Distribution

16. *Extensions:*
Budget: $4,322,000 Forecast: $4,734,000 Variance: $412,000

The extensions forecast is being affected by a customer driven project to deliver power to the Pitcher's Pond Golf Course ($75,000), along with the takeover of the Argentia distribution system from the Argentia Management Authority ($190,000). In addition, residential customer growth remains stronger than expected ($147,000).

17. *Street Lighting:*
Budget: $952,000 Forecast: $1,233,000 Variance: $281,000

Installation of new streetlights in St. John's Region has increased significantly as a result of customer driven demand ($231,000). In addition, a greater than expected number of streetlights have had to be replaced ($50,000).

18. *Transformers:*
Budget: $4,975,000 Forecast: $4,895,000 Variance: -$80,000

The reduction in this forecast reflects a reduced requirement for transformers (-$80,000).

19. *Rebuild Distribution Lines:*
Budget: $3,504,000 Forecast: $3,449,000 Variance -$55,000

The variance in this item is the result of additional work on the SPR-03 project, offset by the deferral of the GLV-02 Extend Line to Charlottetown project. The GLV-02 project will be carried forward into 2004.

20. *Distribution Reliability Initiative:*
Budget: $1,078,000 Forecast: $1,247,000 Variance: $169,000

The project to improve feeder GLV-02 in the Terra Nova National Park area was increased to accommodate the route approved by Parks Canada ($195,000). This was somewhat offset by a reduction in MIL-02 based on a lower than expected contract price for pole replacement (-$26,000).

2003 Capital Expenditure Status Report
Notes

Distribution

21. Improve Distribution System Protection/Operation:
Budget: $457,000 Forecast: $719,000 Variance: $262,000

The original budget was prepared based on historical expenditures. In 2002 we moved towards a more structured approach to carrying out work based on the feeder inspection program. The inspections not only identify defects but also identify various "program" requirements such as CLF requirements, Lightning arrestor requirements, etc. The revised forecast for Distribution System Protection reflects the decision to complete all required "protection" work identified on the feeders that were inspected in 2002.

22. Extension – Cow Head:
Budget: $0 Forecast: $450,000 Variance: $450,000

This is a customer driven project that was not anticipated when the 2003 Capital Budget was prepared.

2003 Capital Expenditure Status Report
Notes

General Property

23. *Tools and Equipment:*
Budget: $770,000 Forecast: $827,000 Variance: $57,000

This variance is the result of increased costs to replace workstations and upgrade furniture at the Kenmount Road Building ($23,000) and Gander Office ($6,000), along with a higher than expected cost for the purchase of a tension stringer ($38,000).

24. *Additions to Real Property:*
Budget: $140,000 Forecast: $220,000 Variance: $80,000

This variance is the result of required building renovations at the Kenmount Road Building ($48,000) and the Gander Office ($21,000) to meet standards.

2003 Capital Expenditure Status Report
Notes

Transportation

25. *Purchase of Vehicles and Aerial Devices:*
    Budget: $2,141,000 Forecast: $2,328,000 Variance: $187,000

    The change in this category is due to the fact that the cost of the heavy vehicle fleet units are approximately 6% higher than budget and an increase in cost associated with factory inspections and commissioning of the units.

26. *Purchase of Vehicles and Aerial Devices (2002 Project):*
    Budget: $2,200,000 Forecast: $2,357,000 Variance: $157,000

    The increase in this category resulted from the receipt of a line truck in 2002 that was part of the 2001 purchase ($157,000).

2003 Capital Expenditure Status Report
Notes

Telecommunications

27. Replace/Upgrade Communications Equipment:
Budget: $242,000 Forecast: $205,000 Variance: -$37,000

The deficiencies identified through inspections required less effort than originally estimated.

28. Substation Telephone Circuit Protection:
Budget: $141,000 Forecast: $89,000 Variance: -$52,000

An engineering study into the actual versus calculated ground potential rise at substations in the Newfoundland environment has been deferred pending the outcome of a Canadian Electricity Association review.

2003 Capital Expenditure Status Report
Notes

Information Systems

29. *Application Enhancements:*
Budget: $766,000 Forecast: $836,000 Variance: $70,000

The increase in this project reflects an increase in the functional requirements to enhance Business Support Systems including employee self-service improvements ($45,000), as well as an increase in the effort required to develop a SCADA information reporting application for system analysis purposes ($30,000).

30. *Application Environment:*
Budget: $755,000 Forecast: $846,000 Variance: $91,000

The increase in this project reflects increased use of external resources required to upgrade to current versions of the Oracle database, Powerhouse development tools and the OpenVMS operating system ($155,000). This also reflects the increased effort required to improve environment management procedures for the Facilities Management, SCADA and Spill Reporting applications ($60,000). This is partly offset by a deferral of the Microsoft Great Plains upgrade from Version 6.0 to Version 7.0, now planned for 2004 (-$124,000).

31. *Personal Computer Infrastructure:*
Budget: $634,000 Forecast: $564,000 Variance: -$70,000

The reduction in this project reflects lower than anticipated pricing of new Personal Computers (-$70,000).

32. *Shared Servers Infrastructure:*
Budget: $1,411,000 Forecast: $1,561,000 Variance: $150,000

A site assessment conducted by the vendor identified additional requirements for hardware and labour to upgrade the Unix operating system and SCADA software ($150,000).

2003 Capital Expenditure Status Report
Notes

Information Systems

33. *Operations Support Systems (2002 Project):*
Budget: $1,322,000 Forecast: $765,000 Variance: -$557,000

During the assessment of functional requirements for this project, it became apparent that the requirement could be met by utilizing a software module installed in conjunction with the Business Support Systems project. When combined with the work completed in 2001, the overall labour cost of the project was reduced (-$557,000).

34. *Facilities Management (2002 Project):*
Budget: $939,000 Forecast: $804,000 Variance: -$135,000

During the assessment of functional requirements for this project, the Company decided to reduce the scope and focus on two asset categories. When combined with the work completed in 2001, the overall labour cost of the project was reduced (-$135,000).

2003 Capital Expenditure Status Report
Notes

Unforeseen Items

35. *Allowance for Unforeseen Items:*
Budget: $750,000 Forecast: $375,000 Variance: -$375,000

This item is necessary to cover any unforeseen capital expenditures that have not been budgeted elsewhere. Projects, for which these funds are intended, are justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment. We have reduced the forecast for this item as we have completed half of the year without utilizing any of these funds.

Information Technology Strategy
2004 - 2008

NEWFOUNDLAND POWER
A FORTIS COMPANY

Contents

1. OVERVIEW

Newfoundland Power's IT strategy remains unchanged since 1999.

Newfoundland Power will continue to invest in technology to improve customer service and operating efficiency.

The current levels of customer service and cost control would not have been possible without the investment that the Company has made in IT. Maintaining and improving upon the gains in operating efficiency and customer service is essential to providing reliable service to customers at least cost.

2. BACKGROUND

During the course of Newfoundland Power's 2003 Capital Budget Application, the Company's planned 2003 expenditures on information technology ("IT") were reviewed.

In Order No. P.U. 36 (2002-2003), the Board of Commissioners of Public Utilities ("the Board") directed Newfoundland Power to prepare an updated IT Strategy Report for the period 2004-2008 as part of its 2004 Capital Budget Application.

This report is submitted in response to the Board's direction. It provides an overview of Newfoundland Power's IT strategy, describes how technology is supporting key functions, and outlines the Company's progress and plans in using IT to improve operating efficiency and customer service.

A description of the components of IT is found in Appendix A.

3. IT STRATEGY

3.1 A Look Back:

This section of the report explains how the Company's investments in IT have contributed to improvements in customer service and operating efficiency.

In 1999, Newfoundland Power's *IT Strategy 1999 to 2002* was filed with the Board as required by Order No. P.U. 36 (1998-1999). In summary, the Company's IT strategy involved the alignment of its IT investments with the imperatives of operating efficiency and customer service. Over the 1999-2002 period, the Company planned to invest $17.7 million in computer software applications and technology infrastructure. Actual investments over that period amounted to $16.9 million, a variance of approximately 5 percent.

IT investment has allowed the Company to remain responsive to the needs of customers by:

1. increasing its ability to react to the changing demands of customers and business partners;
2. improving effective communications between the Company and its customers;
3. efficiently processing large volumes of transactions during the normal course of business;

4. enhancing its ability to be more responsive to electrical system problems affecting customers; and
5. automating business processes to improve customer service and reduce costs.

Specific examples of the benefits of IT investments at Newfoundland Power can be found in Appendix B.

In 2001, the Canadian Information Productivity Awards recognized the Company with two awards in Customer Care for *Utilizing Technology to Deliver Superior Customer Service*. These awards recognized the positive impact that the Company's IT investment has made in providing service to customers.

The Company's focus has been to invest in sustainable and flexible IT applications and computing infrastructure. The Company has adopted a conservative approach to the selection of its IT assets, making informed choices from among the variety of technologies available and ensuring that the installed technologies are effectively managed. The Company has established several guiding principles to help direct its technology investment decisions. These can be found in Appendix C.

In the period 1999-2002, the primary issues that challenged effective IT investment management were obsolescence and rapid technological change. Responding effectively to these issues means not only making wise technology choices, but also choosing the most appropriate time to invest.

Highlights of the Company's investment in IT over the past five years include:

1. implementation of new technology within the Customer Contact Centre to handle customer inquiries and trouble calls;
2. implementation of a new software application to support the handling and reporting of trouble calls across the province;
3. implementation of a new system control and data acquisition ("SCADA") system to provide the capability and capacity for the Company to remotely monitor and control more of the electrical distribution system;
4. establishment of an Internet website that provides customers with another option of conducting business with the Company;
5. implementation of a new hand held meter reading system to collect meter readings from customer's premises;
6. implementation of a new software application to assist with the efficient management of electrical system assets;
7. implementation of a new software application to support the financial, human resources, payroll, purchasing, and inventory aspects of the Company; and
8. establishment of an Intranet to facilitate efficient communications and information sharing amongst employees across the province.

3.2 A Look Forward:

This section of the report describes the continuity of the Company's IT strategy for the next five years, which is to make investment technology decisions that will improve customer service and reduce costs. This strategy will be achieved primarily by making further investments in enhancing the technologies that are already installed throughout the Company.

General

Newfoundland Power's IT Strategy remains essentially unchanged from that described in *IT Strategy 1999 to 2002*. The Company will invest in technology to improve customer service or enable improved operating efficiency.

Newfoundland Power will remain focused on aligning its IT investment decisions with improving customer service and reducing costs. As well, the Company intends to extend and protect the value of its technology investments through regular enhancements and upgrades.

Over the next five years, the Company's IT investments will be focused more on getting further value out of its existing technology investments, and less on the implementation of new applications as in the past five years.

The current software applications in use throughout the Company provide many opportunities to make investments in order to obtain further efficiency gains and continue to improve service to customers. Some specific opportunities are outlined in the Company's 2004 Capital Budget Application under Application Enhancements. As new versions of existing software become available from vendors, new opportunities to gain efficiencies and improve customer service will also be available.

Obsolescence and Change

IT components eventually become obsolete for either technical or functional reasons. Technical obsolescence occurs when a technology component, such as a personal computer ("PC") or a software program, becomes outdated or unreliable, or is no longer supported by the vendor that developed the component. Functional obsolescence occurs when the demands on a computer system evolve to the point where the system is incapable of providing the required functionality in a cost effective manner.

The Company monitors industry developments with the assistance of leading consulting companies such as the Gartner Group[1] to ensure that its IT remains effective, and its investment decisions are sound. Advanced notice of obsolescence issues is critical to (1) ensuring that the Company is able to respond to these issues in a manner consistent with providing least cost reliable service to its customers, and (2) protecting the gains that have already been realized in customer service and operating efficiency through the use of technology.

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand technology and drive business growth. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 80 locations worldwide.

Change can also present challenges unrelated to obsolescence. The proliferation of PCs in the home, coupled with the ubiquity of the Internet, provides customers and business partners with a new way to interact with the Company. At the same time, the Internet has brought with it many new security issues that threaten the availability and integrity of computer systems worldwide, necessitating investments in security software and monitoring tools to protect IT investments and customer information.

4. 2004 CAPITAL BUDGET

This section of the report describes the planned 2004 capital expenditures in the Information Systems category of the Company's 2004 Capital Budget Application.

4.1 General

To continue to achieve value from its technology investments once they have been implemented, effective management of the technology assets are required. A description of the elements of effective technology management is provided in Appendix D.

The primary focus for the next five years, beginning in 2004, will be to invest in the technology already implemented in order to gain additional value from the Company's technology investments to the benefit of customers.

4.2 Applications

Application Enhancements

Enhancing existing applications to improve efficiencies and customer service will be a major focus for the Company. Applications such as the Customer Service System ("CSS"), the Internet and Intranet applications, Operations and Engineering applications, Business Support Systems, and SCADA will be enhanced to provide additional functionality. These enhancements will help to increase productivity, reliability and/or customer service and are a less expensive alternative to purchasing new applications. The proposed expenditures on these items are classified under the heading "Application Enhancements" in Schedule B to the 2004 Capital Budget Application.

Application Environment

Investment in the Application Environment is necessary to upgrade outdated technology and to take advantage of newly developed capabilities as part of the upgraded technology. The Application Environment, which includes the software products, development tools, and related components, is essential to ensuring that changes made to software applications are sufficiently tested and stable before deploying into the production environment, thereby mitigating the risks of downtime and customer service interruption. The proposed expenditures on this item, which also includes the payment for Microsoft Office and related software, are classified under the heading "Application Environment" in Schedule B to the 2004 Capital Budget Application.

Customer Systems Replacement

In 2003, the Company undertook a study to assess the viability of the existing CSS in light of pending technological obsolescence related to the OpenVMS operating system. After a thorough analysis, the Company has decided to keep the existing CSS beyond the current planning horizon, and will reassess the status of the CSS and the OpenVMS obsolescence issue in 2006.

A report entitled *Customer Service System Replacement Analysis* is submitted as Attachment A in Information Systems, Appendix 3 to the 2004 Capital Budget Application.

While the Company has decided to keep the CSS on the OpenVMS operating system, some of the smaller applications that integrate with the CSS will be moved to another operating system. Moving smaller applications from OpenVMS will increase the flexibility in customer communication at reduced cost. The proposed expenditures on this item are classified under the heading "Customer Systems Replacement" in Schedule B to the 2004 Capital Budget Application.

4.3 Infrastructure

Personal Computers

The Company will continue to effectively manage the life cycle of its PCs. Only employees with the appropriate application requirements will receive a new PC. Older, less powerful PCs will be reassigned or "cascaded" to employees with lesser capacity requirements. This extends the useful life of PCs and minimizes costs. The industry standard life is from three to five years. Over the past two years, the Company has been averaging a life cycle in excess of four years for its PCs. Also included in this project is the purchase of various shared devices such as printers and scanners and associated software. The proposed expenditures on this item are classified under the heading "Personal Computer Infrastructure" in Schedule B to the 2004 Capital Budget Application.

Network Infrastructure

The existing network equipment has reached the end of its useful life. In 2003, the Company began the process of upgrading its "wide area network". This network interconnects all area offices across the province back to St. John's. In 2004, the Company will complete the upgrade. This upgrade will reduce the risk of an interruption in service resulting from a hardware component failure, as the hardware components being implemented are more widely supported by the vendors. This item also covers the replacement of the "local area network" equipment within the area offices. This equipment is seven years old and has reached the end of its useful life. The proposed expenditures are classified under the heading "Network Infrastructure" in Schedule B to the 2004 Capital Budget Application.

Shared Server Infrastructure

Investment in Shared Server Infrastructure is required to complete hardware upgrades and replacements that are necessary to maintain current performance standards and to accommodate additional application and data requirements. This item also covers the replacement of tape drives used for performing backups for all of the Company's data that is stored on disks connected to servers. These tape drives are reaching the end of their useful life and have been prone to failure. Also included are upgrades to the SCADA infrastructure and security. The proposed expenditures on this item are classified under the heading "Shared Server Infrastructure" in Schedule B to the 2004 Capital Budget Application.

5. CAPITAL OUTLOOK: 2005 TO 2008

This section of the report describes the forecast 2005 to 2008 capital expenditures in the Information Systems category of the Company's Capital Budget.

5.1 General

Information Systems capital expenditures are expected to range from $3.5 million to $3.8 million over this period. The primary focus will be to extend the life and value of the existing investments in applications and technology infrastructure.

Monitoring of the CSS's continuing viability on the OpenVMS platform with a view to maximizing the system's life will be a key risk through this period. At this time, the projected IT capital expenditures through 2008 do not include any costs associated with replacing the CSS.

The dynamic nature of the IT industry makes it difficult to accurately predict future expenditure requirements. However, past experience and industry trends allow the Company to make informed estimates. The following assessment is based on just such estimates.

5.2 Projected Capital Spending: 2005 to 2008

Table 1 provides a summary of the Company's planned or projected capital expenditures on IT for the period 2005 to 2008.

Table 1
IT Capital Expenditure
(000s)

Category	2005	2006	2007	2008
Applications	$ 2,050	$ 2,245	$ 2,110	$ 2,185
Infrastructure	$ 1,700	$ 1,350	$ 1,350	$ 1,455
Total	**$ 3,750**	**$ 3,595**	**$ 3,460**	**$ 3,640**

5.3 Applications

Enhancements to existing applications will continue until new technology makes it more cost effective to replace the applications. Total investment in applications for the years 2005 to 2008 are forecast to be in the range of $2.1 million to $2.2 million per year.

Investments in application software upgrades will increase in the years 2006 and 2008, as many of the Company's application software products will require upgrades. Software vendors usually release new versions of their products every 18 months. Companies like Newfoundland Power must keep pace with these upgrades in order to retain support and maintenance from the vendor. As well these upgrades often provide new functions and features that enable the Company to take advantage of new customer service opportunities and additional efficiencies. For example, the Company expects that upgrades to the technology systems supporting the Customer Contact

Center will allow for more efficient and effective handling of e-mail, Internet and other electronic contacts with customers. Finally, investments in the upgrading of application software ensure that the applications needed to support functions such as customer service continue to be available. Annual expenditures in this area for 2005 to 2008 are forecast to average approximately $758,000.

Enhancements to the existing operations and engineering applications are estimated approximately at $388,000 per year. A new asset management application, to manage the maintenance of the Company's substation and generation assets, will be implemented in 2003. Enhancements to this application over time will allow the Company to improve operating efficiencies and customer service through the increased reliability of its system assets. As well, further improvements will be made to the SCADA application and to systems supporting work planning, scheduling and tracking over the period.

Enhancements to the CSS will continue as customer demands change and business process improvements are required. CSS enhancements are forecast to average approximately $372,000 per year.

Enhancements to other customer related systems will increase in 2005 as systems such as the outdated Cash Register System will require replacing at this time.

For the period 2005 to 2008, the Company will make additional investments in the Business Support Systems in order to continue to improve operating efficiencies. Annual expenditures are forecast at an average of approximately $131,000 each year.

Each year, the Company allows for minor improvements to all applications for unforeseen changes as a result of legislated requirements, changes required by external parties such as Canada Post, and for minor improvement opportunities identified by customers and employees. Annual expenditures are forecast at an average of approximately $150,000 a year.

Newfoundland Power will continue to invest in Internet and Intranet technology as customers' use of the technology grows, and to provide employees with improved capability to respond to customer's requests using more accurate and readily available information. Investments in the Internet and Intranet are forecast to remain stable over the 2005 to 2008 period, averaging approximately $156,000 each year.

As described in the *Customer Service System Replacement Analysis* report, the core CSS is expected to remain on OpenVMS for the next five years, with a re-assessment taking place in 2006. However, portions of the CSS will continue to be moved away from OpenVMS. Annual expenditures are forecast to average approximately $193,000 over the 2005 – 2008 timeframe.

5.4 Technology Infrastructure

Investment in the technology infrastructure will continue as the existing infrastructure ages and requires replacement, and advances in hardware technology allow for more efficient and reliable support of the Company's business applications. Total technology infrastructure investments for the years 2005 to 2008 are forecast to be in the range of $1.4 million to $1.7 million per year.

Continued investment in PCs will be necessary as the existing technology reaches the end of its useful life. New technologies, such as thin-client computing, are beginning to mature that will serve to extend the useful life of PCs even further. While the number of PC replacements and the cost per unit will vary from year to year, the total annual cost is projected to average approximately $550,000.

By the end of 2004, the Company will have replaced the major components of the communication network. In 2005, an investment of $250,000 will be required to accommodate application requirements such as information reporting and data backups. Beyond 2005, an annual investment of approximately $50,000 is necessary to accommodate network growth.

Application reliability and the need to effectively manage the technology infrastructure is very important for the provision of reliable customer service at least cost. Investments in infrastructure monitoring and security enhancements are forecast to average approximately $58,000 per year.

Ongoing investment in the server infrastructure is required to ensure the continued availability of the applications, such as the CSS, that reside on these servers. Expenditures involve upgrades to server components such as disks and memory and the replacement of servers that have reached the end of their useful life. Expenditures in server infrastructure are expected to average approximately $705,000 annually over the 2005 to 2008 period. Similar technology upgrades will also be required for the SCADA infrastructure to ensure that this application remains available to monitor and control the electrical system. Investment in the SCADA infrastructure is forecast to average approximately $50,000 annually.

6. IT TRENDS

This section of the report provides a view of developing trends in IT, from a utility perspective. Investment in these technologies by Newfoundland Power will be determined by the realizable improvements in customer service and operating efficiency that can be achieved.

Newfoundland Power keeps informed of emerging IT trends through various sources such as leading industry analyst organizations like the Gartner Group and Meta Group[2], industry publications such as Public Utilities Fortnightly, Platt's Energy Business and Technology, and Computing Canada, software supplier user groups as well as attending industry conferences and online seminars. With a focus on cost savings and customer service Newfoundland Power takes a conservative approach to implementing IT, ensuring that trends are well established and can provide value to the Company and its customers. Should specific trends justify capital expenditures, the Company will budget for them accordingly.

The following is a summary of the IT trends, from a utility perspective, that the Company is monitoring.

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[2] META Group is a research and advisory firm that helps more than 3,300 businesses in 40 countries understand technology and drive business growth. Unlike Gartner and other advisory firms, META Group also provides vertical expertise and coverage of the IT solutions for industries such as energy and utilities.

Mobile computing

Wireless computing is continuing to evolve and is transforming the use of pen and paper. Personal Digital Assistants, Tablet PCs, rugged laptops, digital ink, radio frequency identification and tagging technologies may replace pen and paper. The use of portable mobile computing devices is increasing within the industry. This could provide new opportunities for the Company in improved customer service and operational efficiencies for employees who spend most of their time in the field.

Collaboration and Self-Service

With the increase in the adoption rate of the Internet and such technologies as instant messaging, portals (personalized intranets and internets), interactive voice response and electronic bill payment, sharing information between companies, customers and suppliers continues to increase. With opportunities to increase customer service and satisfaction as well as reduce costs, companies continue to promote customers' use of the Internet and interactive voice response for self-service. Internally, companies look for ways to improve access to information by effectively utilizing technologies for improved document and content management, ad-hoc reporting, and online analytical reporting.

Computing Platforms (including Operating Systems)

Operating systems such as Linux are being implemented in many organizations as a complement, or as an alternative, to other operating systems (such as Unix or Windows). An open source operating system (meaning that it is not owned by one particular vendor), Linux is being used more and more for file, print and web server applications.

Transformation and Reuse

A recent trend in the IT industry is that companies are striving to ensure maximum value is derived from their existing technology investments as opposed to buying more. Companies are doing this by transforming existing applications by upgrading, migrating, consolidating, and integrating. Technological investments are focusing on continual improvement in operational productivity through the automation of manual processes and improved integration with existing technology.

Systems Integration

Integration is being placed at the top of the list of goals for many companies as they strive to create a real-time agile service oriented business. Integration connects business processes, application, data, customers and business partners. Some of the benefits derived include creating a more cohesive and fluid business processing environment while streamlining business responsiveness. Businesses will continue to improve integration between their software applications, external suppliers, and customers to achieve operational efficiency by reducing duplication and inconsistency.

Customer Relationship Management (CRM)

CRM applications provide functionality in sales, marketing, call centres, customer service and support. The trend of integrating them back into back office systems (financial, human resources) and customer information systems will continue as organizations implement these solutions to complement their existing customer service processes. This may help to improve operational efficiency and customer service.

Business Process Outsourcing
The delegation of business processes to external service providers that own and/or manage the process will continue to rise, allowing organizations to focus on core business with the potential to improve existing processes and reduce overall operating costs.

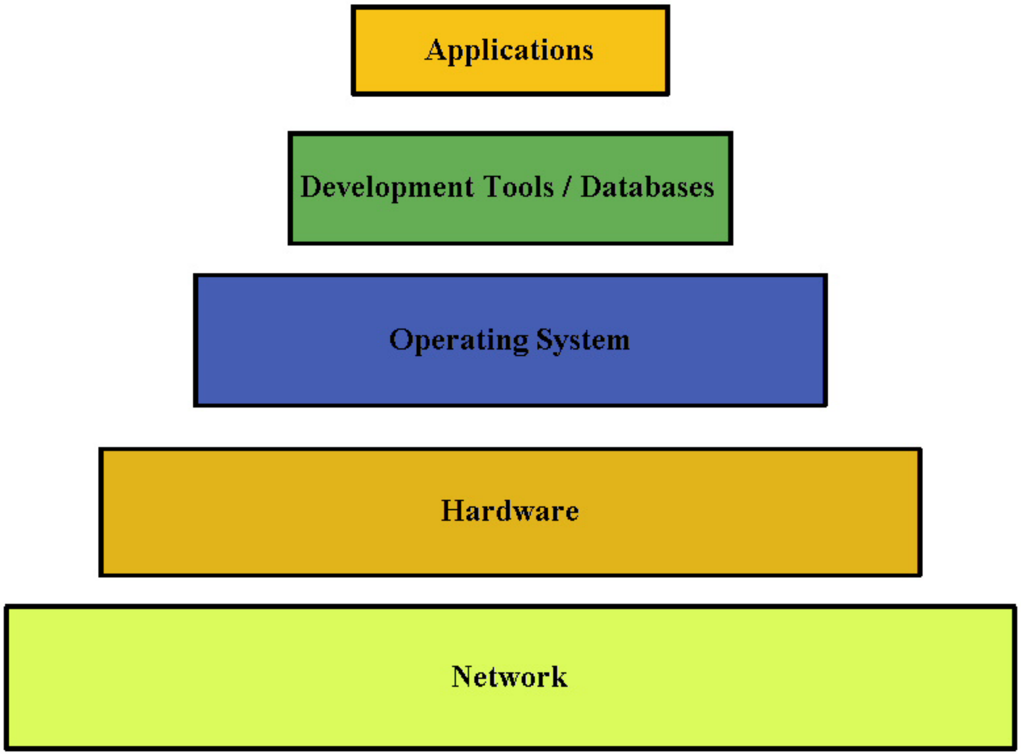
Newfoundland Power will continue to carefully consider the experience of other organizations and to employ industry best practices in its evaluation and management of IT products and services. This strategy will ensure that the required technology solutions are implemented at a minimum cost over the long term. The Company will monitor trends but will not make significant investment unless the technology will result in improvements in productivity or customer service and are well proven in the industry.

Appendix A

THE COMPONENTS OF IT

Introduction
The term IT encompasses all forms of technology used to create, store, exchange, and use information in its various forms. At Newfoundland Power, there are many different pieces of hardware (computing infrastructure) and software (computer applications) that, in combination, comprise the computer systems that are relied upon to provide service to customers in an efficient manner.

While IT infrastructure can be complex, the basic structure can be simply illustrated as follows:



The Network
The foundation of the entire IT infrastructure is the network. The network is made up of all of the devices and telecommunications services that make communication from one piece of hardware to another possible.

A “wide area network” connects Newfoundland Powers offices across the island back to the central computing facilities in St. John’s. In turn, each individual office has its own “local area network” whereby all of the local hardware is interconnected. A Customer Account Representative (“CAR”) in Corner Brook who wishes to access a customer’s account uses a desktop computer that is connected via the local area network to the Company’s wide area network. The wide area network provides access to the Company’s main Customer Service System (“CSS”) database in St. John’s, upon which the required information is stored.

Upgrades and replacements of network components are generally contained in the Network Infrastructure Project in the Company’s annual capital budgets.

Hardware
The term “hardware” refers to the personal computers and servers, and peripheral devices such as printers, scanners, modems, and handheld meter reading devices. Hardware is required to run the software applications that support business processes. For example, a shared server allows employees throughout the Company’s offices to access and share information found in applications such as the Asset Management System.

Expenditures related to hardware are typically provided for in the Shared Server Infrastructure and Personal Computer Infrastructure budget items of the Company’s capital budgets.

Operating Systems
Operating systems are computer programs that manage all of the other programs that run on the hardware. An operating system functions as the master control program for a computer, and facilitates the running of applications on the computer and the interaction between the computer and peripheral devices such as printers. OpenVMS, Windows 2000, and Unix are some of the operating systems installed on computers at Newfoundland Power.

Operating system upgrades are typically provided for in Newfoundland Power’s capital budgets under the Application Environment and the Shared Server Infrastructure budget items.

Developer Tools and Databases
Developer tools and databases are used to create programs, or applications, that can be installed on operating systems. The developer tools are the computer languages in which applications are written. Databases are used to store information to be accessed by applications. For example, Newfoundland Power’s Oracle database contains the customer information records that are accessed by the CSS application.

Developer tools upgrades and enhancements are typically provided for in Newfoundland Power’s capital budgets under the Application Environment budget item.

Applications
Applications are the computer programs used by employees to perform their jobs in a productive manner. Newfoundland Power uses a variety of applications to support business processes at the corporate, departmental, and individual employee level.

Many applications are common business tools, such as word processors, spreadsheet programs and electronic mail, while others such as the CSS provide functionality that is specific to the Company's business requirements. These applications may be installed on either personal computers or servers, and must work in conjunction with an operating system.

Applications may be either purchased from software vendors such as Microsoft, or created using developer tools, depending on what is feasible in the circumstances.

Applications enhancements are typically provided for in Newfoundland Power's capital budgets under the Application Enhancements budget item, while requirements for new applications are typically identified separately.

Interdependence
All of the IT components described above are interdependent. If there is a failure in any one of these components in an IT system (for example, an electronic mail system), the ability of that system to function as intended will be compromised.

The CSS provides a good illustration of the interdependency of IT components at Newfoundland Power. The CSS application was written using Cognos developer tools and an Oracle database. The application and database reside on a server that is running on the OpenVMS operating system. The Company's Customer Account Representatives use their personal computers to access the application and database via the Company's network.

If any one of these components is unavailable, the Customer Account Representatives cannot access the information necessary to fulfill customers' service requests and inquiries. It is therefore essential that Newfoundland Power continuously monitor all of the IT components that are critical to customer service delivery, employee productivity, and electrical system reliability to ensure they are always functioning as required.

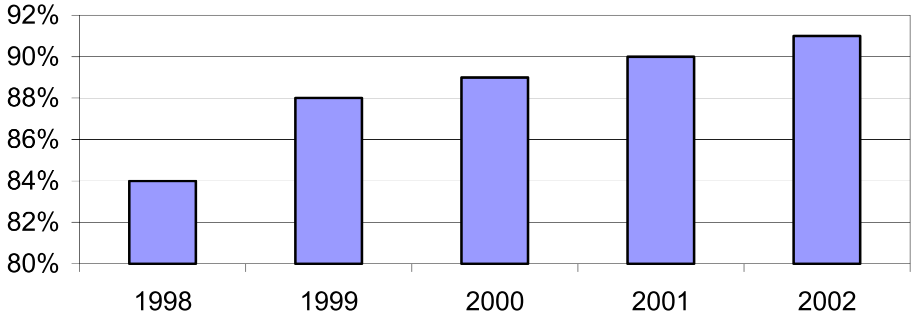
Appendix B

BENEFITS OF IT AT NEWFOUNDLAND POWER

IT is critical for Newfoundland Power to maintain and improve customer service and provide a low cost supply of electrical energy. The benefits of IT at Newfoundland Power can be seen in the following areas:

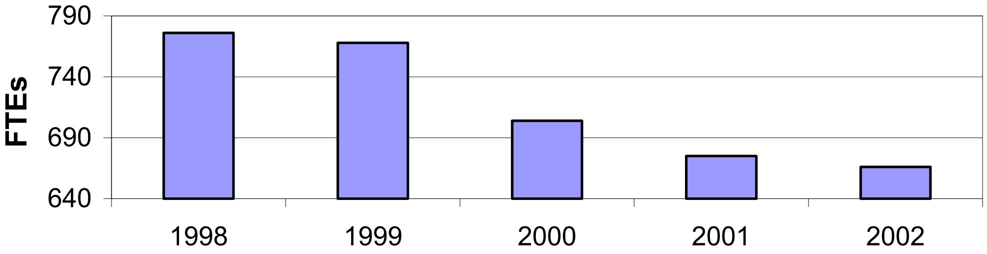
- *Meeting customer expectations* by supporting interactions with customers, enabling flexible services, and accommodating changing customer needs. For example, the Company's Internet site provides twenty-four hour self-service capability, including energy usage graphs and electronic billing. One of the means the Company uses to gauge its level of success in meeting customer expectations is its Customer Satisfaction Index. In 2002, the Customer Satisfaction Index reached an all time high of 91%.

Customer Satisfaction Index



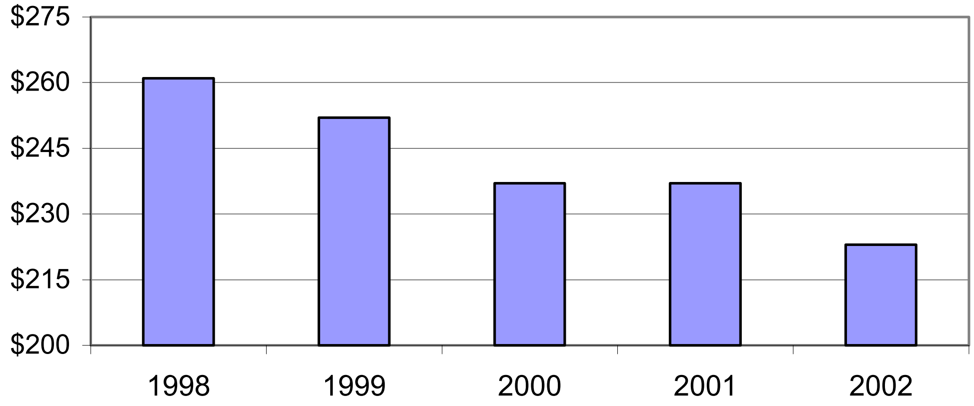
- *Achieving productivity improvements and cost savings* by automating manual processes, reducing transaction costs, and minimizing staff requirements. For example, the use of hand held meter reading devices has reduced the time required to capture and process meter readings and produce a customer's bill from five days to one day. Productivity improvements such as these have helped with reducing the number of Full Time Equivalents ("FTEs"). At year-end 2002, the Company was operating with a workforce of 666 FTEs, a reduction of 14.8% since 1998.

Workforce: 1998 to 2002



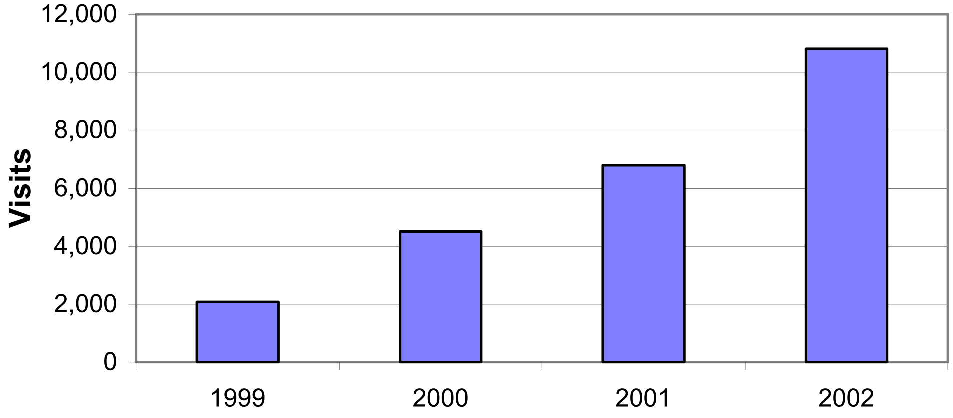
The Company also continues to decrease the operating cost per customer served. Since 1998, the operating costs per customer served have decreased 14.6%.

Operating Costs per Customer Served



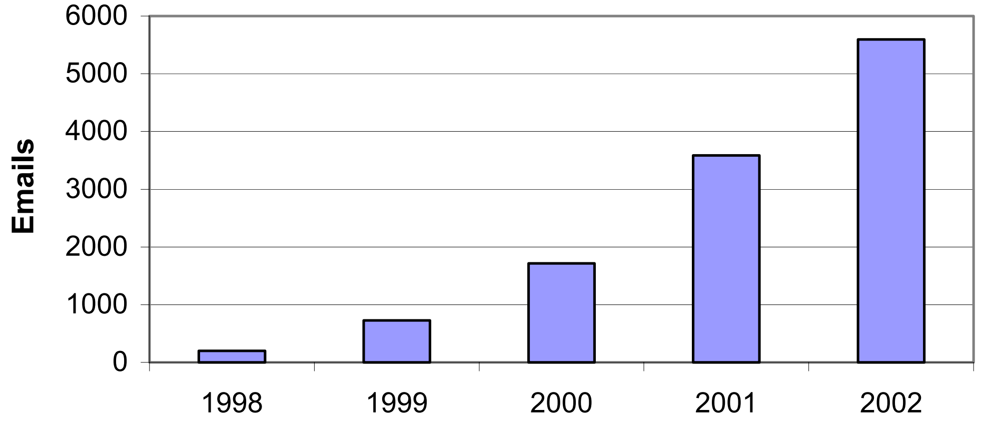
- *Enhancing communications* amongst employees and between the Company, its customers and outside suppliers, by providing the parties with a means to send and receive correspondence in much less time than is possible with traditional methods of communication. Employees are also able to collaborate and share documents from remote distances. The key benefit of enhanced communications is reduced operating costs and quicker response to business and customer requirements. The demand for enhanced communications is rising especially through customer's use of the Internet and email. Since 1999, average monthly visits to the Company's Internet website have increased over 400%.

Average Monthly Visits to Internet Website



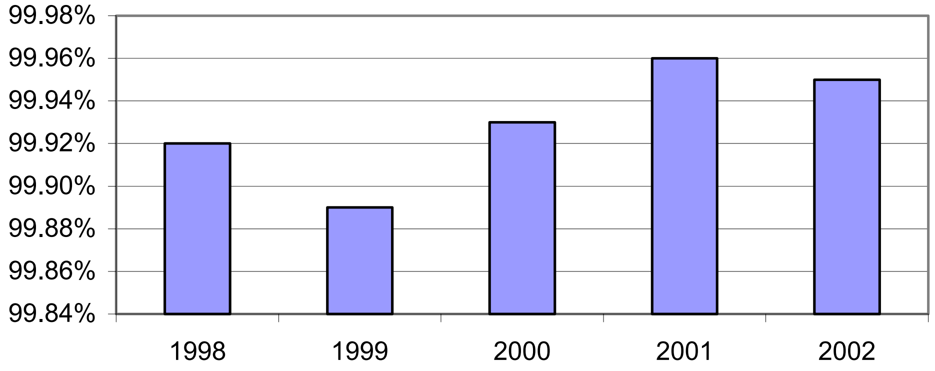
- *Processing large volumes of transactions* efficiently and effectively. Applications such as the CSS and the Back Office Support System ("BOSS") allow the Company to capture, process, and store transactional data for future reference with minimal manual intervention, increased data quality, and reduced operating costs. For example, the CSS allows the company to annually process over 2.4 million bills, 140,000 service orders, and answer over 350,000 customer calls and 5500 customer emails. Since 1998, the number of customer emails to the Company has grown significantly.

Customer's Electronic Correspondence to the Customer Contact Centre



- *Aiding electrical system reliability and power quality* by facilitating improved monitoring, control, and maintenance of the electrical system. Using the SCADA system located in the System Control Centre (“SCC”) in St. John’s, SCC staff monitor the electrical distribution and generating system for problems and can take corrective action immediately.

Electrical System Availability



Appendix C

GUIDING PRINCIPLES

Introduction

To ensure that the Company's investments in IT are effective and are consistent with the Company's obligation to provide reliable service at reasonable cost, Newfoundland Power has adopted certain standard practices that guide its IT investment decisions. These practices were first outlined in the *Information Technology Strategy 1999-2002* filed with the Board in 1999 and continue to guide the Company's IT investment decisions today.

Standard Practices

These standard practices may be summarized as follows:

- Buy from leading vendors
- Minimize the diversity of installed technology
- Buy rather than build technology
- Consider the cost of the product over its lifespan

Leading Vendors

Buying from leading IT vendors helps to ensure ongoing industry support and reduces the risk of premature obsolescence. For example, Microsoft has been the market leader in operating systems and office productivity tools during the past decade. In order to improve the likelihood of ongoing vendor support, Newfoundland Power utilizes Microsoft or Microsoft-compatible office productivity applications wherever it is feasible to do so.

Minimize Diversity

By minimizing the diversity of installed technology, Newfoundland Power can reduce spare parts inventories and minimize staff retraining requirements. For example, Newfoundland Power has adopted HP/Compaq servers as its standard for shared server infrastructure. This minimizes the variety of spare parts, such as hard drives and power supplies, required for the Company's servers.

Broad Company experience with HP/Compaq servers also ensures that staff is familiar with the equipment, which reduces training requirements.

Buy vs. Build

Newfoundland Power prefers to buy rather than custom build technology applications. A custom-built application must be designed, developed, implemented, and supported over its entire life by internal staff resources. With purchased applications, the vendor takes on these responsibilities, allowing the Company to allocate its IT staff to more cost effective activities. IT industry consultant Gartner Group[1] advises that building applications for one's own use is "the most expensive deployment option."[2]

Total Life Cycle Costs
Newfoundland Power also considers the cost of a technology product over its entire lifespan when making purchase decisions. The initial cost of purchasing a technology is but one component of the total cost. When Newfoundland Power evaluates technology solutions, the cost of implementing the technology and the cost of supporting the technology over its entire life are evaluated and taken into account before making an investment decision.

Conservative Adoption of Technology

In addition to following the above principles when making IT choices, Newfoundland Power takes a conservative approach to investing in IT by only adopting proven technology. This means that Newfoundland Power will purchase IT only when it has become established and accepted by other users. By benefiting from the experience of others in this way, Newfoundland Power is able to minimize the risks often associated with leading edge technology.

Conclusion

Newfoundland Power manages its investments in IT in a manner that ensures the total cost is minimized over the longer term. By following the practices described above, Newfoundland Power is able to ensure that its IT purchases are cost-effective.

Where possible and practical, asset life is extended to ensure that the maximum value is attained from the investment. For example, when new PCs are purchased, the PCs that are being replaced are cascaded to other employees, thereby extending the useful life of the PC.

Newfoundland Power must balance cost with risk when making decisions on technology investments. Replacing a technology component is not generally warranted when the product is still performing well. However, as customer service and business requirements evolve, the consequence of not replacing a technology component may outweigh the cost of replacement.

The practices described in these Guiding Principles provide a useful framework for making cost-effective decisions in IT investment.

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[1] Gartner Group is a research and advisory firm that helps more than 11,000 businesses understand technology including 200 utilities. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,300 associates, including 1,400 research analysts and consultants, in more than 90 locations worldwide.

[2] SMB (small and mid size businesses) Applications Deployment: Build, Buy or Rent? February 2001, Robert Anderson, James Browning and Joseph Outlaw.

Appendix D

ELEMENTS OF IT MANAGEMENT

Introduction

IT is essential to enable Newfoundland Power to improve customer service levels and ensure the reliability of the electricity supply in a productive manner. Maintaining an effective IT infrastructure requires ongoing investment.

As functionality requirements evolve and as capacity requirements grow, the Company's IT assets must be enhanced and modified to keep pace. They must be monitored to ensure they are working properly and to alert technical staff to the possibility of technical problems that might lead to downtime. Like any other equipment, they must also be regularly maintained. Finally, provision must be made for the security of the IT infrastructure and, in particular, protection from external infiltration.

Newfoundland Power manages its IT investments in a manner that is consistent with its obligation to provide reliable service to its customers at the lowest possible cost. This requires balancing the need to extend asset life to obtain maximum value from the investment with the need to replace assets before either the cost of maintaining them becomes uneconomic, or they become obsolete from a functional or technical perspective.

Following is a review of each of the elements of IT management.

Enhancements

Most IT components require enhancements at some point to extend their useful lives. As business requirements change, software and hardware must be modified to keep pace. Examples of technology enhancements at Newfoundland Power that meet changing customer requirements include changes to billing and customer information systems to accommodate improved payment plan offerings and the introduction of electronic forms to replace paper.

In other cases, the enhancements implement functional improvements, such as the change in the hand held meter reading system to include CSS service orders for final reading requests from customers.

IT enhancements are typically provided for in Newfoundland Power's capital budgets under the Application Enhancements projects.

Upgrades

An upgrade is a modification to a technology component that extends its useful life by improving usability or providing additional features and functionality. Upgrades are typically made available to users by technology vendors as they release newer versions of their products.

A vendor's progression to a new version of a component may also require the upgrade of some or all of the other components in a computer system. For example, if the CSS Oracle database requires an upgrade to fix a technical problem, the operating system and applications using the database may need to be upgraded as well to ensure they continue to work together properly.

Upgrades are typically provided for in Newfoundland Power's capital budgets in the budget item entitled Application Environment.

Maintenance

Maintenance must be performed regularly on all technology components to ensure they are functioning at an optimal level. Typical examples of computer systems maintenance include performance-tuning, repairs to address hardware failures, data corruption fixes, and disk space management.

Monitoring

In order to sustain productivity and customer service levels, technology must remain reliable and available. A number of manual procedures and automatic diagnostic applications are in place at Newfoundland Power to help predict and prevent failures of computer systems. Automatic applications monitor the Company's critical systems, such as the CSS, and notify technical staff when action is required to prevent a failure. These applications ensure virtually continuous availability of the Company's major business applications.

IT monitoring applications are provided for in the Company's capital budgets under Shared Server Infrastructure.

Security

Another aspect of regular maintenance is the protection of the Company's computer systems from external threats. The well-known electronic threats to computer systems include unauthorized access ("hacking") and electronic mail viruses. Computer systems are also subject to physical disasters affecting Company business premises, such as fire, flood, vandalism and sabotage.

In order to minimize the vulnerability of its computer systems to external interference, the Company conducts regular security reviews. These reviews involve assessments by industry experts of the Company's computer security measures, its security processes and practices, and the skill and knowledge levels of employees. The Company's computer security measures, including employee clearances and facility access, are assessed in light of industry best practices. Attempts to "hack" into the Company's computer systems are also conducted in order to confirm the adequacy of existing security measures, particularly those that protect corporate and customer information.

To address the possibility of physical threats, the Company has disaster recovery processes in place, including backup computer facilities at its Duffy Place building in St.

John's. In the event of a major disruption to computer services at the Company's main computer facility on Kenmount Road, these disaster recovery processes will ensure that the Company can successfully recover its computer services in a timely fashion.

The Company's computer disaster recovery processes include formal and documented action plans that must be updated regularly to reflect changes in the business and computing environment. The Company also conducts regular disaster recovery drills to ensure that participants are adequately prepared and to identify areas where improvement may be necessary.

Ongoing investment in such security measures is necessary to ensure that the Company's computer systems remain effective and reliable.

Capital investments in IT security are provided for in the Company's capital budgets under Shared Server Infrastructure.

Obsolescence

IT components eventually become obsolete for either technical or functional reasons. Technical obsolescence occurs when a technology component, such as a PC or a software program, becomes outdated or unreliable, or is no longer supported by the vendor that developed the component. Functional obsolescence occurs when the demands on a computer system evolve to the point where the system is incapable of providing the required functionality in a cost effective manner.

Obsolescence affects all IT at Newfoundland Power including software, the network, servers, and operating systems. Decline in vendor support for an IT component can render the component obsolete, whether or not the component remains technically or functionally useful. When this occurs, the Company must assess the costs and benefits associated with supporting the component "in-house" against replacing the component with newer, and supported, technology components.

The Company monitors industry developments to ensure the continued reliability of its IT resources. Industry information on technical obsolescence enables the Company to take appropriate measures to minimize its impact on the Company's IT assets. For example, because industry and vendor support for the OpenVMS operating system is in decline, the Company has chosen not to install any new OpenVMS applications.

Obsolescence permeates all aspects of IT management at Newfoundland Power. Projects to address obsolete technology may be found in any number of the Company's capital budget projects.

2004
Capital
Budget
Plan

July 25th, 2003

NEWFOUNDLAND POWER
A FORTIS COMPANY

CONTENTS

I. OVERVIEW

In Order No. P.U. 36 (2002-2003) (the "Order"), the Board of Commissioners of Public Utilities for Newfoundland and Labrador (the "Board") expressed its view that stable and predictable year over year capital budgets was a desirable objective for Newfoundland Power (the "Company"). In the Order, the Board also recognized that uncertainties and exigencies faced by the Company would challenge year over year capital expenditure stability.

The 2004 Capital Budget Plan (the "Plan") was prepared with a view to providing a measure of stability to the Company's capital expenditures over the period 2004 through 2008. The Plan also reviews expenditures over the period 1993 through 2003 and indicates the material factors that influenced capital expenditure patterns through this period.

While the Company accepts the Board's view of the desirable effects of year to year capital expenditure stability, the nature of the utility obligation to serve will not, in some circumstances, necessarily facilitate such stability. The Plan has identified some risks to such stability in the period 2004 through 2008.

As the Company progresses through the 2004 through 2008 period, its view of the capital expenditures necessary to fulfill its obligation to serve can be expected to change. In proposing annual capital expenditures, the Company will have due regard for the Board's stated desire for relative year to year stability in capital budgets.

II. CONTENTS OF THE PLAN

This report is filed by Newfoundland Power as part of its 2004 Capital Budget Application in compliance with the Board's directives in the Order.

Further to the directives contained in the Order, the Plan includes the following:

- An analysis of capital expenditures, both budgeted and actual, for the period 1993 through 2003.
- A breakdown of the expenditure patterns for each budget category and for the overall capital budget for each year.
- A full explanation of the reasons for the changes in expenditure patterns over the period 1993 through 2003.
- A five-year plan for maintaining the stability of the capital budget and the capital works program, including an assessment of the maximum budget growth and a contingency for unexpected or unusual events during the period.

III. CAPITAL EXPENDITURES: 1993 - 2003

This section of the report analyzes capital expenditures for the period 1993 through 2003 and examines the changing capital expenditure patterns and variances from budget over this period.

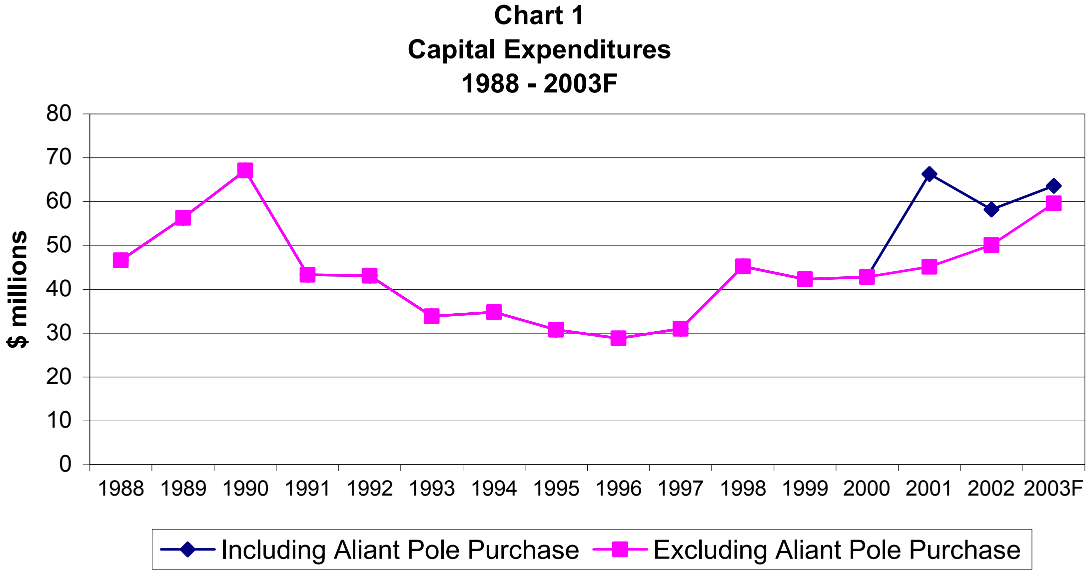
A. Analysis of Capital Expenditures: 1993 - 2003

The year 1993, which is the first of the ten years under review, was also the first full year following the cod moratorium in 1992. The cod moratorium materially affected the economy of the province, and with it, the capital expenditures of Newfoundland Power, for at least the next five years.

In order to provide a context for comparison of the capital expenditures for the period following the cod moratorium it is useful to consider capital expenditure levels prior to 1993. Chart 1 below provides information regarding capital expenditures for the period 1988 to forecast 2003.

As shown in the chart, capital expenditures over the past 16 years have ranged from a high of approximately $67 million in 1990 to a low of approximately $29 million in 1996. Closer analysis of the expenditures indicates that, excluding expenditures related to the purchase of joint use poles from Aliant Telecom Inc. (Aliant), average capital expenditures (unadjusted for inflation) during the 1999 to forecast 2003 period are lower than expenditures incurred during the 1988 to 1992 period.

Overall, the most significant reason capital expenditures have increased over the period 1993 to forecast 2003 relates to the replacement of deteriorated, defective or obsolete plant and equipment. In recent years, the Company adopted a more proactive approach that balances the maximization of the life of the asset with delivery of electrical energy to customers at the lowest possible cost consistent with reliable service.



B. Changing Capital Expenditure Patterns: 1993 – 2003

During the 1993 through 1997 period actual capital expenditures were fairly constant, averaging approximately $32 million per year. Since 1997, actual capital expenditures have averaged approximately $53 million per year.

An analysis of capital expenditures by both capital budget category and origin is included in Appendix A. The budget category for capital expenditures signifies the type of asset, for example, transmission. The origin of capital expenditure determines the reason for the expenditure, for example, customer/sales growth.

Charts 2 and 3 summarize capital expenditures by budget category and origin respectively for the period 1993 through forecast 2003. Given the extraordinary and self-sustaining nature of the capital expenditures related to the purchase of joint use poles from Aliant, they have been excluded from the analysis of capital expenditures by origin shown in Chart 3. This will enable a more comparative year over year analysis of the composition of the Company's capital expenditures.

Chart 2
Capital Expenditures by Budget Category
1993 - 2003F

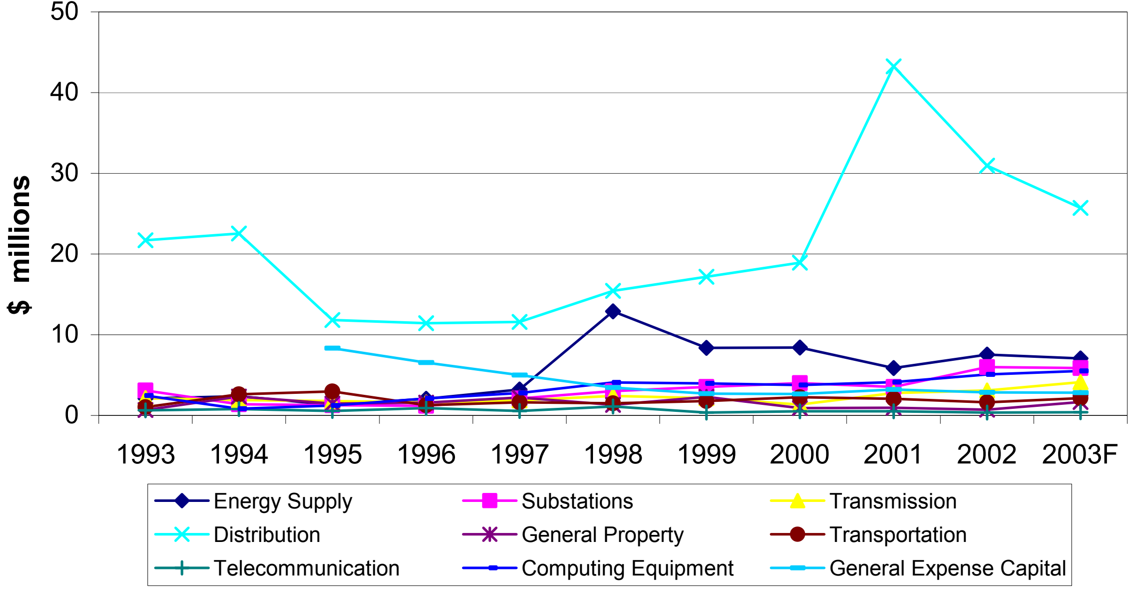
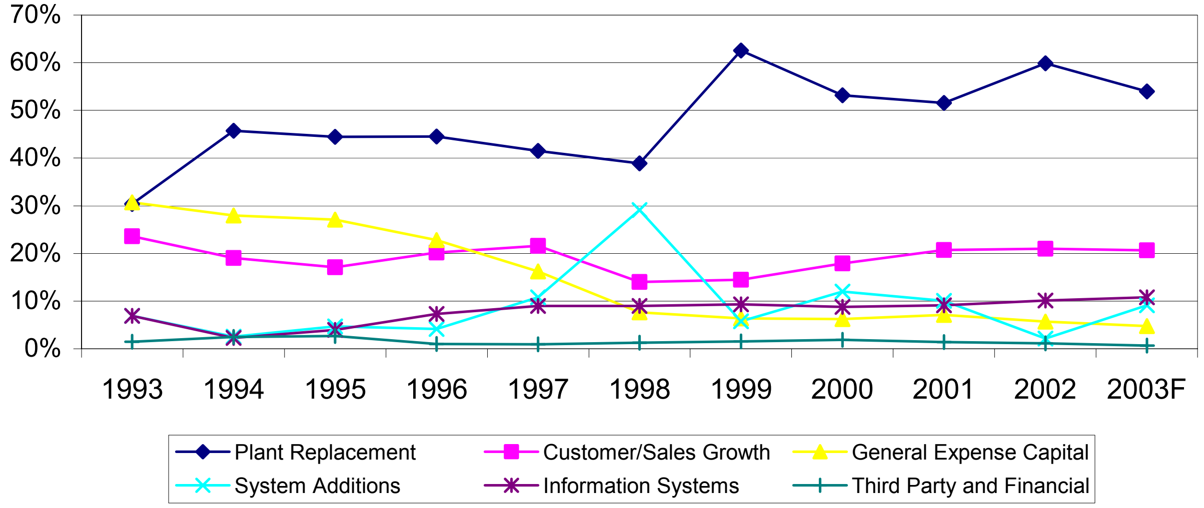


Chart 3
Capital Expenditures by Origin
1993 - 2003F



Analysis of the budget category and origin of capital expenditures for the period 1993 through forecast 2003 indicates that the changing pattern of capital expenditures is materially influenced by the following factors:

1. Purchase of Aliant poles;
2. The Rose Blanche Hydroelectric Plant;
3. Plant Replacement;
4. Customer Demand;
5. Information systems;
6. General expenses capitalized; and
7. Inflation.

1. Purchase of Aliant poles

The distribution capital budget category increased dramatically in 2001. This was due to the acquisition of the Aliant joint-use poles for approximately $41 million. This resulted in additional distribution capital expenditures of $21.2 million in 2001, $8.1 million in 2002 and $4.0 million in 2003.

The purchase of the Aliant joint-use poles was justified by economies of scale which have the effective result of reducing the amount of pole costs required to be recovered in electricity rates.

2. The Rose Blanche Hydroelectric Plant

System additions in the energy supply budget category increased when the Rose Blanche Hydro Plant, which was commissioned in 1998 at an approximate cost of $13.5 million, was added to the system.

3. Plant Replacement

Newfoundland Power is primarily a distribution utility. Improvements in the reliability of the service the Company provides will be to a large extent, but not totally, a function of the quality of the distribution system.

Plant replacement has accounted for an increasing proportion of capital expenditures since 1999. From 1993 through 1998, plant replacement accounted for between 30% and 46% of the Company's capital expenditures. Since 1999, that proportion has consistently exceeded 50% (excluding capital expenditures related to the Aliant joint-use pole acquisition).

Since 1999, Newfoundland Power has undertaken targeted initiatives to improve distribution reliability by rebuilding its poorest performing distribution feeders.

As part of its 2003 general rate application the Company filed a new depreciation study, conducted by depreciation expert Gannett Fleming. The study recommended lower annual depreciation rates principally because the Company's assets, including its distribution assets, are expected to last longer. The Company believes that the outcome of this depreciation study is an indication that its plant replacement strategy is working.

Depreciation is the loss of asset service value not restored by current, or operating, maintenance. Annual depreciation expense is expected to approximate $30 million in 2003 which is also approximately 50% of the most current forecast of the 2003 capital budget. While depreciation is not intended to reflect replacement cost, the fact that the order of magnitude of the depreciation expense and the amount expended on asset replacement are similar does provide some indication of the appropriateness of the Company's plant replacement strategy.

4. Customer Demand

The obligation to serve requires the Company to make capital expenditures to meet customer demand. Customer demand, in turn, is reflective of economic conditions.

With improved economic conditions in recent years, the level of expenditures related to the installation of new plant and equipment necessary to meet customer/sales growth requirements has increased. Capital expenditures related to customer/sales growth have ranged from a low of $5.3 million in 1995 to a high of $12.2 million in 2003.

As shown on Chart 3, the percent of total capital expenditures related to customer/sales growth declined from 1993 through 1998. Since 1998, with improved economic conditions the percent of total capital expenditures related to customer/sales growth and meeting customer requirements has increased.

5. Information systems

Information Systems capital expenditures as a percent of total capital expenditures showed a gradual increase during the 1993 through 2003 period. This area of capital expenditures has been directed towards improving customer service and responsiveness and maintaining overall operating efficiency of the Company.

6. General expenses capitalized

While all other factors discussed in this section result in increased capital expenditures in recent years, the decline in General Expense Capital ("GEC") has reduced the Company's annual capital budget. The decline flows from Order No. P.U. 3 (1995-96) which directed the Company to change its method of allocating GEC. As a result, GEC which is included as part of the Company's annual capital budget has declined from approximately $10 million in 1993 to approximately $3 million in 2003. Prior to 1995, GEC was not shown as a separate budget category but included as part of the various budget categories.

7. Inflation

Given the long life of most utility assets (approximately 30 years) , the replacement cost of assets will tend to be significantly higher than current embedded costs simply as a result of inflation. During the 1993 through 2003 period inflation as measured by the Gross Domestic Product Implicit Price Deflator increased by approximately 20%. Over the past 30 years, inflation has been in the order of 350 per cent. This implies that the replacement cost of a 30-year old asset can be multiples of the original cost.

C. Capital Expenditure Variances from Budget

Budget variances are unavoidable given the time between the completion of the budget process and the execution of capital projects. Variances can arise due to any number of factors including: changes in the work due to third parties; changes in priority due to new events; changes in engineering or cost estimates; price changes or delays in the delivery of material and equipment; and, other unforeseen circumstances that could not be reasonably anticipated during budget preparation.

From 1993 through forecast 2003 there were a number of factors that have impacted capital expenditure variances from budget.

First, the volatility of economic conditions varied significantly during the period. If forecasts of customer and energy growth are either lower or higher than actual experience, capital expenditures related to customer and energy growth will typically be correspondingly lower or higher than budget. In recent years economic growth has been higher than anticipated and as a result capital expenditures related to customer and energy growth are higher than budgeted.

Second, since 1997 the Company has completed a full review of its budget methodology and continues to make modifications where appropriate. As a result the accuracy of the Company's budgeting has improved.

Third, the Company now submits the budget earlier in the year for regulatory approval. This enables the Company to start work earlier in the year if winter conditions permit. Therefore, the need to either cancel or defer a project due to time constraints is reduced.

As a result of these factors the overall level of capital expenditure variances from budget has been reduced. Appendix B contains a detailed breakdown of material variances by budget category along with an explanation of those variances.

IV. CAPITAL BUDGET PLAN

This section of the report outlines a five-year capital budget plan (the "Plan") for maintaining the stability of the capital budget, including an assessment of risks to the Plan which could cause budget growth to exceed that planned. In addition, this section assesses maximum budget growth and contingencies for unusual events during this period.

A. Plan Overview

The Company plans to invest approximately $260 million in plant and equipment during the 2004 through 2008 period. Over the period capital expenditures are forecast to remain relatively stable and consistent with the average for the past six years. Capital expenditures are expected to average approximately $53 million annually and range from a low of $49 million in 2008 to a high of $52 million in 2006.

In recent years, the Company has focused attention on rural distribution lines where reliability has been appreciably worse than the Company average. Over the next 5 years, the Company will continue its efforts to refurbish distribution lines that have performed poorly with respect to reliability. These distribution lines tend to be either very old, or are exposed to abnormally adverse weather conditions.

The Plan also provides for the refurbishment of a number of the Company's aged and deteriorated transmission lines. Many of these lines have been in service for in excess of 40 years, and inspections have revealed deterioration resulting from their long exposure to harsh weather and salt contamination. In other locations, it has been determined that the original line design does not provide adequate vertical clearance.

The Plan will continue to address the issue of radial systems, which rely on a single link between the energy source and customers. On radial systems a failure of any critical component will result in an outage in all of the communities supplied by the system. As a result, customers served by radial systems generally experience more and longer power interruptions than those served by looped systems. Radial lines to Old Perlican and New-Wes Valley are currently addressed in the Plan. Other radial systems like Trepassey and Port-aux-Basques will be analyzed further and may impact capital budgets in the future.

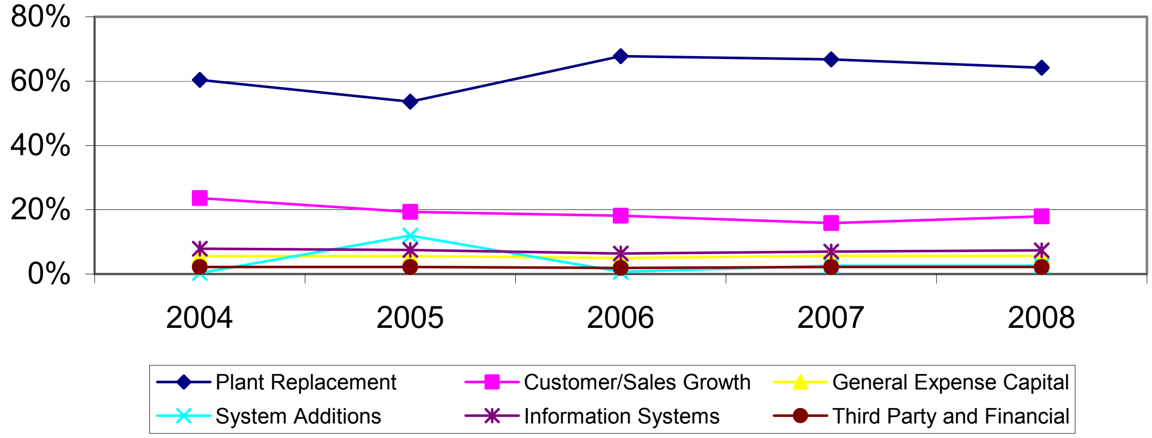
Many of the Company's hydro generating plants, substations and office buildings are in excess of 50 years old. The Plan will address the replacement of major components at many of these facilities in order to remove deteriorated or obsolete plant from service. The Plan addresses replacing penstocks at the New Chelsea, Rattling Brook, Hearts Content and Rocky Pond hydroelectric plants. These expenditures are required to maintain energy production levels and to maintain safe and reliable service to customers.

The Company will continue to invest in information technology to maintain existing systems, as well as invest in projects that introduce further improvements in customer service, operational efficiency and public and employee safety.

B. Plan by Origin and Category

The Plan continues to focus on the replacement of deteriorated, defective or obsolete electrical equipment which accounts for approximately 60% of total expenditures (excluding the purchase of joint-use poles from Aliant). Mirroring forecast economic performance for the province, the expenditures related to customer and sales growth are expected to decline from 22% of total expenditures in 2004 to 18% in 2008.

Chart 4
Capital Expenditures By Origin
2004F - 2008F



A summary of planned capital expenditures for the 2004 - 2008 period by category along with a breakdown by project is contained in Appendix C. Overall, planned expenditures are expected to remain stable in all categories with the exception of Energy Supply, Transmission and Distribution. The following briefly summarizes each category.

1. Energy Supply

The Energy Supply category includes capital expenditures related to the replacement of deteriorated plant and equipment at the Company's hydro plants and thermal generating stations, as well as the purchase of a portable generator in 2004. While these facilities are relatively small when viewed as stand-alone production centers, collectively they displace approximately 700,000 barrels of oil (at an estimated annual cost of approximately $20 million) burned at Newfoundland and Labrador Hydro's Holyrood Thermal station, contribute to system reliability and, in many cases, provide a source for local backup.

With the exception of 2006, Energy Supply capital expenditures average $5.4 million per year. The increase in 2006 is related to the rehabilitation of the Rattling Brook Plant, the Company's largest hydroelectric plant. This major project includes the replacement of the penstock, surge tank and other key components of the plant.

2. Substations

The Substation category includes capital expenditures related to rebuilding substations, replacement and spare substation equipment, feeder remote control, and the addition of transformer capacity. The replacement and spare substation equipment capital expenditures involve the replacement of items such as circuit breakers, reclosers, potential transformers, batteries and other equipment that either fail in service or have reached the end of their useful lives. The projects in this category focus on improved system reliability and operational efficiency, safety, reduced environmental risk associated with oil-filled reclosers, and responding to customer growth.

Substation capital expenditures are expected to average $6.2 million annually over the 2004 through 2008 period.

3. Transmission

The Transmission category includes capital expenditures related to rebuilding transmission lines. The projects include: replacement of poles, crossarms, and conductor; replacement of pin type and suspension insulators; and improvement of conductor sag and clearances. The projects also include the construction of a new line that will convert the existing Old Perlican radial system to a looped system. The projects in this category are primarily focused on reliability and safety.

Transmission expenditures will increase from $2.3 million in 2004 to an average of $6.2 million annually over the 2005 through 2008 period.

4. Distribution

The Distribution category includes capital expenditures for extensions, services, street lighting and transformers that are influenced by growth in the number of customers served by the Company. These capital expenditures are determined with reference to the Company's forecast of new customers using historical capital expenditures as a guide. This category also includes reconstruction projects that are primarily focused on maintaining reliability and safety.

The Distribution category also includes capital expenditures related to the relocation of plant at the request of third parties. A significant portion of these costs are recovered from the parties making the request.

Distribution capital expenditures are expected to decline from $27.6 million in 2004 to $19.4 million in 2008. The decline in capital expenditures is related to forecast reduced growth in the number of customers served and the completion of the purchase of the joint-use poles from Aliant in 2005. During this period capital expenditures related to the replacement of deteriorated, defective or obsolete plant and equipment are expected to remain stable and similar to the capital expenditures recorded in 2003.

5. General Property

The General Property category includes capital expenditures for the addition or replacement of tools and equipment utilized by line and support staff in the day-to-day operation of the Company, as well as the replacement or addition of office furniture and equipment. The category includes additions to real property necessary to maintain buildings and facilities and to operate them in an efficient manner.

General Property capital expenditures are expected to average $1.0 million annually over the 2004 through 2008 period.

6. Transportation

The Transportation category includes the replacement of existing heavy fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors including kilometres traveled, vehicle condition, operating experience and operating expenditures.

Transportation capital expenditures are expected to average $2.7 million annually over the 2004 through 2008 period.

7. Telecommunications

The Telecommunications category includes the replacement or upgrading of various communications systems. These systems contribute to customer service, safety, and maintenance of power system reliability by supporting communications between the Company's fleet of mobile vehicles and the various plants and offices.

Telecommunications capital expenditures are expected to average $0.3 million annually over the 2004 – 2008 period.

8. Information Systems

The Information Systems category includes: the replacement of personal computers, printers and associated assets; upgrades to current software tools, processes, and applications as well as the acquisition of new software licenses; and, the development of new or enhancements to existing applications to support changing business requirements and take advantage of new developments and product improvements.

Information Systems capital expenditures are expected to average $3.7 million annually over the 2004 through 2008 period.

C. Plan Risks

Newfoundland Power has an obligation to serve customers located in its service territory. Therefore, should customer and energy growth vary from forecast so will the capital expenditures which are sensitive to growth. For instance, the Company is aware of a potential mine that, if developed, would require additional capital expenditures in the order of $5 million. Due to the uncertain nature of the project proceeding at this time it was not included in the Plan.

The Plan partially addresses the issue of radial systems. These systems currently experience more and longer power interruptions than those served by looped systems. While the Plan includes looping the system serving the Old Perlican area in 2005, at an estimated cost of approximately $5.1 million, no further projects of this nature are included in the Plan beyond 2005. This is an area where the Company intends to focus engineering effort in the future to determine a viable solution for these areas. Any projects flowing from this could put upward pressure on the Plan.

The Company's Customer Service System ("CSS") is 11 years old. As the replacement cost of a CSS system could be as high as $15 million the Company is taking steps to extend the life of CSS through 2008. Accordingly, while the Company has no plans to replace CSS during the 2004 through 2008 period, changing technology and vendor support could conceivably dictate otherwise. Eventual replacement of the CSS will likely be staged over more than 1 year.

Overall, planned capital expenditures are forecast to be relatively stable during the 2004 through 2008 period, however, circumstances can change and, as a result, so will priorities and the level of capital expenditures.

Assessment of maximum budget growth in this period necessarily involves a significant degree of conjecture. Given that a single customer addition (i.e., such as the one mentioned above) could add additional capital expenditures of $5 million, a maximum annual capital budget could approximate $60 million. In such a case, it is expected that certain otherwise justifiable projects might be deferred in a way that minimizes the negative impact of deferral on the quality of service.

In each year of the Plan, the Company's forecast budget includes $750,000 for unforeseen items and $150,000 for unidentified major electrical equipment repairs. This amounts to a total of almost $1 million per year in the nature of contingency for unexpected or unusual events.

While these amounts are not in the nature of *approved* expenditures, they provide an allowance for unexpected events of almost 2% of the average budget. The allowance of a larger contingency of, say, 5% of the average budget, or approximately $2.6 million, would permit greater flexibility to the Company. However, the number of supplementary approvals required in recent years has not been unduly large or burdensome.

Newfoundland Power Inc.
Capital Budget Expenditures - By Budget Category
(000s)

Budget Category	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003F** [1]
Distribution	$ 21,710	$ 22,527	$ 11,840	$ 11,448	$ 11,580	$ 15,422	$ 17,171	$ 18,928	$ 43,257	$ 30,966	$ 27,614
	64.1%	64.8%	38.5%	39.8%	37.4%	34.1%	40.6%	44.2%	65.2%	53.2%	43.7%
Energy Supply	2,115	2,378	1,321	2,061	3,225	12,888	8,359	8,430	5,871	7,520	9,194
	6.2%	6.8%	4.3%	7.2%	10.4%	28.5%	19.8%	19.7%	8.9%	12.9%	14.5%
Substations	3,104	1,372	1,278	1,179	2,102	3,029	3,529	4,000	3,542	5,986	8,040
	9.2%	3.9%	4.2%	4.1%	6.8%	6.7%	8.3%	9.3%	5.3%	10.3%	12.7%
Computing Equipment	2,451	829	1,214	2,105	2,775	4,080	3,953	3,754	4,124	5,074	6,399
	7.2%	2.4%	3.9%	7.3%	9.0%	9.0%	9.3%	8.8%	6.2%	8.7%	10.1%
Transmission	2,140	1,907	1,790	1,634	1,855	2,425	2,149	1,334	2,765	3,089	4,291
	6.3%	5.5%	5.8%	5.7%	6.0%	5.4%	5.1%	3.1%	4.2%	5.3%	6.8%
General Expenses Capital	-	-	8,346	6,556	5,014	3,465	2,682	2,678	3,211	2,868	2,800
	0.0%	0.0%	27.1%	22.8%	16.2%	7.7%	6.3%	6.3%	4.8%	4.9%	4.4%
Transportation	1,036	2,616	2,964	1,273	1,639	1,521	1,797	2,276	2,061	1,609	3,076
	3.1%	7.5%	9.6%	4.4%	5.3%	3.4%	4.3%	5.3%	3.1%	2.8%	4.9%
General Property	688	2,352	1,477	1,584	2,213	1,294	2,298	930	944	715	1,047
	2.0%	6.8%	4.8%	5.5%	7.1%	2.9%	5.4%	2.2%	1.4%	1.2%	1.7%
Telecommunications	618	792	552	930	562	1,121	344	506	530	343	418
	1.8%	2.3%	1.8%	3.2%	1.8%	2.5%	0.8%	1.2%	0.8%	0.6%	0.7%
Unforeseen											375
											0.6%
Total	**$ 33,862**	**$ 34,773**	**$ 30,782**	**$ 28,770**	**$ 30,965**	**$ 45,245**	**$ 42,282**	**$ 42,836**	**$ 66,305**	**$ 58,170**	**$ 63,254**
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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[1] Includes carryovers from 2002.

Newfoundland Power Inc.
Capital Budget Expenditures - By Origin
(000s)

Origin	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003F[1]
Plant Replacement	$ 10,290	$ 15,900	$ 13,673	$ 12,815	$ 12,863	$ 17,609	$ 26,441	$ 22,780	$ 23,236	$ 29,980	$ 31,969
	30.4%	45.7%	44.4%	44.5%	41.5%	38.9%	62.5%	53.2%	35.0%	51.5%	50.5%
Customer/Sales Growth	7,999	6,612	5,273	5,812	6,680	6,350	6,124	7,678	9,345	10,510	12,238
	23.6%	19.0%	17.1%	20.2%	21.6%	14.0%	14.5%	17.9%	14.1%	18.1%	19.3%
Information Systems	2,334	790	1,215	2,105	2,775	4,080	3,953	3,754	4,124	5,073	6,399
	6.9%	2.3%	3.9%	7.3%	9.0%	9.0%	9.3%	8.8%	6.2%	8.7%	10.1%
System Additions	2,347	895	1,447	1,201	3,340	13,178	2,440	5,144	4,524	1,088	5,409
	6.9%	2.6%	4.7%	4.2%	10.8%	29.1%	5.8%	12.0%	6.8%	1.9%	8.6%
Aliant Pole Purchase	0	0	0	0	0	0	0	0	21,238	8,088	4,044
	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	32.0%	13.9%	6.4%
General Expense Capital	10,393	9,718	8,346	6,556	5,014	3,465	2,682	2,678	3,211	2,868	2,800
	30.7%	27.9%	27.1%	22.8%	16.2%	7.7%	6.3%	6.3%	4.8%	4.9%	4.4%
Third Party Requirement	389	765	735	203	217	481	549	719	549	483	295
	1.1%	2.2%	2.4%	0.7%	0.7%	1.1%	1.3%	1.7%	0.8%	0.8%	0.5%
Financial	110	93	93	78	76	82	93	83	78	80	100
	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.2%
Total	**$ 33,862**	**$ 34,773**	**$ 30,782**	**$ 28,770**	**$ 30,965**	**$ 45,245**	**$ 42,282**	**$ 42,836**	**$ 66,305**	**$ 58,170**	**$ 63,254**
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

[1] Includes carryovers from 2002.

Newfoundland Power Inc.
Capital Budget Summary
1993 – 2003
($000s)

	Approved by Board Order	Actual[1]	Variance Total	Variance (%)
1993	35,180	33,862	(1,318)	(3.7)
1994	39,724	34,773	(4,951)	(12.5)
1995	38,023	30,782	(7,241)	(19.0)
1996	30,958	28,770	(2,188)	(7.1)
1997	33,204	30,965	(2,239)	(6.7)
1998	43,460	45,245	1,785	4.1
1999	41,031	42,282	1,251	3.0
2000	41,771	42,836	1,065	2.5
2001	63,028	66,305	3,277	5.2
2002	57,839	63,698	5,859	10.1
2003	55,715	57,726[2]	2,011	3.6

[1] Actual expenditures reflect the ultimate expenditures pursuant to approvals of the Board given in the year. Carryovers of projects to subsequent years are reflected in year of approval.

[2] Includes 2003 supplementary capital expenditures of $721,000 for which Board approval had not yet been granted at time of filing.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1993
(000s)

	Approved By Board Order [1]	Actual	Variance Over (Under)
Energy Supply	$ 2,240	$ 2,115	$ (125)
Substations	3,191	3,104	(87)
Transmission	2,660	2,140	(520)
Distribution	22,826	21,710	(1,116)
General Property	1,156	688	(468)
Transportation	1,175	1,036	(139)
Telecommunications	425	618	193
Computing Equipment	1,507	2,451	944
General Expenses Capital	-	-	-
	$ 35,180	**$ 33,862**	**$ (1,318)**

[1] Order Nos. P.U. 11 (1993), P.U. 1 (1993) and P.U. 2 (1993).

Lower than anticipated customer and sales growth in 1993 was the principle contributing factor for 1993 variances.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1994
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 2,967	$ 2,378	$ (589)
Substations	1,492	1,372	(120)
Transmission	2,801	1,907	(894)
Distribution	24,629	22,527	(2,102)
General Property	2,233	2,352	119
Transportation	3,720	2,616	(1,104)
Telecommunications	900	792	(108)
Computing Equipment	982	829	(153)
General Expenses Capital	-	-	-
	$ 39,724	**$ 34,773**	**$ (4,951)**

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[1] Order Nos. P.U. 4 (1993-94), P.U. 1 (1994-95) and P.U. 5 (1994-95).

Energy Supply: The decrease resulted from the cancellation of several projects which, through detailed analysis, proved not to be feasible.

Substations: The decrease resulted from deferral of a power transformer installation due to lower than expected peak low.

Transmission: The decrease resulted from deferral of several projects.

Distribution: The decrease resulted from deferral of a street light conversion project which proved not to be feasible due to high contract labor price. As well, one large distribution extension project was cancelled as the particular mine site was not developed.

General Property: The increase was the result of major storm related damage.

Transportation: The decrease was due to a delay in large vehicle deliveries from 1994 to 1995.

Telecommunications: A project to review alternatives for integration of data circuits was deferred to 1995.

Computing Equipment (Information Systems): The decrease resulted from the deferral of application development projects from 1994 to 1996.

General Expense Capital: This cost was incorporated into other categories.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1995
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 2,049	$ 1,321	$ (728)
Substations	1,416	1,278	(138)
Transmission	2,312	1,790	(522)
Distribution	14,698	11,840	(2,858)
General Property	1,588	1,477	(111)
Transportation	3,175	2,964	(211)
Telecommunications	888	552	(336)
Computing Equipment	1,397	1,214	(183)
General Expenses Capital	10,500	8,346	(2,154)
	$ 38,023	**$ 30,782**	**$ (7,241)**

[1] Order No. P.U. 6 (1994-95).

Energy Supply: The decrease in cost was attributed to a number of projects that were deferred due to contract prices or other issues which made the projects uneconomical.

Substations: The deferral of an additional power transformer at Virginia Waters due to decreased load growth was the primary reason for the decrease in cost.

Transmission: The deferral of several transmission line upgrade projects resulted in the decreased cost.

Distribution: The decrease in this category results mainly from lower than anticipated customer driven work and a decision to defer certain projects to address concerns related to low customer and sales growth.

General Property: The deferral of several projects by making minor repairs instead resulted in actual costs being lower than budget.

Transportation: The decision to defer vehicle purchases to address concerns related to the decline in customer and sales growth resulted in cost reductions.

Telecommunications: The decrease in cost resulted from the deferral of projects due to staffing losses in the Telecommunications Department.

Computing Equipment (Information Systems): The decrease in costs resulted from deferral of several software applications pending further review of requirements.

General Expense Capital: The decrease in this category was a direct result of reductions in total capital budget as a consequence of reductions in other categories.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1996
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 2,360	$ 2,061	$ (299)
Substations	1,224	1,179	(45)
Transmission	1,758	1,634	(124)
Distribution	12,336	11,448	(888)
General Property	1,711	1,584	(127)
Transportation	1,788	1,273	(515)
Telecommunications	943	930	(13)
Computing Equipment	2,340	2,105	(235)
General Expenses Capital	6,498	6,556	58
	$ 30,958	**$ 28,770**	**$ (2,188)**

[1] Order No. P.U. 5 (1995-96).

Energy Supply: The decrease in this category resulted from a deferral in payment for certain projects due to lack of progress on material delivery. As well, design change for certain projects allowed significant cost reduction.

Substations: Minimal variance.

Transmission: The decrease resulted primarily from a deferral of several line relocation projects due to delays in road construction and resolution of litigation issues.

Distribution: The decrease resulted from lower than anticipated customer and sales growth in certain areas, as well as a reduction in the Department of Transportation activity associated with the TCH upgrade and cutbacks in NewTel's fibre cable placement program.

General Property: The decrease in this category resulted from deferral of certain equipment such as the fall arrest equipment which was deferred pending the results of a CEA study.

Transportation: The decrease is the result in a delay in the delivery of several line trucks to 1997.

Telecommunications: Minimal variance.

Computing Equipment (Information Systems): The decrease was the result of a number of projects costing less than the budgeted amount.

General Expenses Capital: Minimal variance.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1997
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 3,726	$ 3,225	$ (501)
Substations	1,992	2,102	110
Transmission	2,008	1,855	(153)
Distribution	12,794	11,580	(1,214)
General Property	2,247	2,213	(34)
Transportation	2,286	1,639	(647)
Telecommunications	1,074	562	(512)
Computing Equipment	2,054	2,775	721
General Expenses Capital	5,023	5,014	(9)
	$ 33,204	**$ 30,965**	**$ (2,239)**

[1] Order No. P.U. 9 (1996-97).

Energy Supply: The decrease in this category resulted from lower than anticipated material cost for certain projects and the cancellation of several others.

Substations: The increase resulted from higher than anticipated cost for insulator replacement projects and the conversion of crown leases to grant project.

Transmission: The decrease resulted from a deferral of a major line relocation project pending resolution of litigation issues.

Distribution: The decrease resulted from cancellation of a meter replacement project and lower than anticipated third party initiated work in the St. John's and Avalon areas.

Transportation: A reassessment of vehicle usage and realignment resulting from an early retirement program for employees allowed the Company to decrease vehicle purchases.

Telecommunications: The decrease resulted from the cancellation of the PBX project after a detailed assessment identified a more cost effective solution.

Computing Equipment (Information Systems): The increase in this category resulted from increased costs associated with the IT migration project and licensing fees for Microsoft Office.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1998
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 13,121	$ 12,888	$ (233)
Substations	2,660	3,029	369
Transmission	2,640	2,425	(215)
Distribution	13,402	15,422	2,020
General Property	2,193	1,294	(899)
Transportation	1,415	1,521	106
Telecommunications	1,173	1,121	(52)
Computing Equipment	3,439	4,080	641
General Expenses Capital	3,417	3,465	48
	$ 43,460	**$ 45,245**	**$ 1,785**

[1] Order Nos. P.U. 15 (1997-98), P.U. 17 (1997-98) and P.U. 17 (1998-99).

Energy Supply: The decrease was due primarily to the deferral of several projects to 1999 due to severe weather conditions in late 1998.

Substations: The increase in costs occurred as a result of additional requirements being identified for several projects when detailed design work commenced.

Transmission: The decrease resulted from a deferral of several projects due to delay in road construction and resolution of litigation issues.

Distribution: Increased transformer replacements due to storm damage and the distribution transformer replacement program resulted in increased costs. As well, there was unforeseen distribution reconstruction required to address storm damage in St. John’s.

General Property: The budget for general property included a $750,000 provision for unforeseen expenditures; the actual costs, however, were reported within the appropriate class of assets.

Transportation: The increase cost was the result of new vehicle purchases, planned for 1999, being actually received very late in 1998.

Computing Equipment (Information Systems): The increased cost was associated with the Technical Environment Migration of the Customer Service System. (External contractors were used at a higher level than originally anticipated.) As well, the original budget for the Year 2K project did not include a plan to repair all applications in 1998. However, consistent with most companies, Newfoundland Power decided to accelerate the completion of the project to reduce Year 2K risks.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 1999
(000s)

	Approved By Board Order[1]	Actual	Variance Over (Under)
Energy Supply	$ 7,710	$ 8,359	$ 649
Substations	2,989	3,529	540
Transmission	2,114	2,149	35
Distribution	16,143	17,171	1,028
General Property	2,876	2,298	(578)
Transportation	1,946	1,797	(149)
Telecommunications	453	344	(109)
Computing Equipment	4,174	3,953	(221)
General Expenses Capital	2,626	2,682	56
	$ 41,031	**$ 42,282**	**$ 1,251**

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[1] Order Nos. P.U. 36 (1998-99), P.U. 6 (1999-2000) and P.U. 18 (1990-2000).

Energy Supply: The increase in costs resulted from the carryover of several 1998 projects due to unfavourable weather conditions late in 1998.

Substations: The increase in costs is due to several reasons. One involved the carryover of a project from 1998 that was deferred to a time when the load on the system was lower. The remainder was due to greater than anticipated costs to replace switches, crossarms and insulators.

Distribution: The increased costs resulted from extension projects associated with providing new services being higher than anticipated as well as several unanticipated large extensions to serve new commercial customers and cottage areas.

General Property: The $750,000 allowance for unforeseen items was not required for expenditures in 1999.

Transportation: Actual expenditures were lower than plan as a result of the receipt of new vehicles planned for 1999 in 1998 as well as a delay in the delivery of two line trucks to 2000.

Telecommunications: The decrease was the result of the cancellation of a fibre optic networking project.

Computing Equipment (Information Systems): The decrease was due mainly to reassignment of resources to Year 2K project and partial deferral of Disaster Recovery project.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 2000
(000s)

	Approved By Board Order [1]	Actual	Variance[2] Over (Under)
Energy Supply	$ 8,878	$ 8,430	$ (448)
Substations	3,500	4,000	500
Transmission	1,526	1,334	(192)
Distribution	16,358	18,928	2,570
General Property	1,585	930	(655)
Transportation	2,390	2,276	(114)
Telecommunications	537	506	(31)
Computing Equipment	4,147	3,754	(393)
General Expenses Capital	2,850	2,678	(172)
	$ 41,771	**$ 42,836**	**$ 1,065**

[1] Order No. P.U. 18 (1999-2000).
[2] Variance details are outlined in the 2000 Capital Expenditure Summary Report filed with the Board on Feb. 28, 2001.

Energy Supply: The decrease is due mainly to lower than anticipated costs to replace the Horse Chops penstock. The difference resulted from lower material cost and reduced labour cost due to the absence of any major complications or unexpected delays in the project.

Substations: The increase was primarily due to the substation site improvement and build new substation (St. Catherine's) projects. The first required significantly more fencing and signage than originally anticipated. Detailed engineering for the second project identified that the original design and location was not technically feasible; unfortunately, the alternative proved to be more costly.

Transmission: The decrease resulted from a deferral of several insulator replacement projects as well as the deferral of the line relocation associated with the construction of the Conception Bay North bypass road.

Distribution: The increase stems primarily from an increase in the number of customer requests for service, some of which required significant extensions. As well, the results of field surveys identified a significant number of transformers that required immediate replacement.

General Property: The $750,000 allowance for unforeseen items was not required for expenditures in 2000.

Transportation: Fewer units than anticipated were replaced in 2000.

Computing Equipment (Information Systems): A project to replace the existing workflow environment was deferred pending further investigation. As well, the Company was able to negotiate a lower than anticipated price for personal computers.

General Expense Capital: This variance reflects a greater portion of internal labour being charged to specific capital projects than originally planned.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 2001
(000s)

	Approved By Board Order[1]	Actual	Variance[2] Over (Under)
Energy Supply	$ 5,619	$ 5,871	$ 252
Substations	2,863	3,542	679
Transmission	2,419	2,765	346
Distribution	41,586	43,257	1,671
General Property	1,723	944	(779)
Transportation	1,866	2,061	195
Telecommunications	683	530	(153)
Computing Equipment	3,619	4,124	505
General Expenses Capital	2,650	3,211	561
	$ 63,028	**$ 66,305**	**$ 3,277**

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[1] Order Nos. P.U. 24 (2000-2001), P.U. 12 (2001-2002) and P.U. 17 (2001-2002).

[2] Variance details are outlined in the 2001 Capital Expenditure Summary Report filed with the Board on March 1, 2002.

Energy Supply: The increase is mainly attributable to unanticipated costs associated with the Sandy Brook runner upgrade and the System Control Centre SCADA projects.

Substations: The variance in this category is primarily the result of increased scope associated with the Rebuild Substation project that was identified during the detailed engineering phase.

Transmission: The variance in this category resulted from a detailed analysis which identified that the length of line requiring upgrade was more extensive than originally anticipated, as well as an unanticipated request from the Department of Works to relocate sections of three transmission lines.

Distribution: Extensions and services associated with providing electricity to new customers increased as a result of more residential customers than anticipated as well as several unanticipated large extensions to service new commercial customers and cottage areas.

General Property: The $750,000 allowance for unforeseen items was not required for expenditures in 2001.

Transportation: The increase resulted from a decision to upgrade the specifications for two line trucks from light duty to heavy duty to obtain a better match between the truck and work requirements.

Telecommunications: The decrease resulted from a delay in the Telephone Circuit Protection project due to other work commitment by Aliant Inc.

Computing Equipment (Information Systems): The increase resulted from greater than anticipated modification to the Business Support System, as well as an increase in the work in progress associated with the Facilities Management and Operations Support Systems.

General Expense Capital: The increase in this category was due to increased effort associated with the 2001 capital budget as well as increased expenditure associated with vacation, payroll and material overhead.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 2002
(000s)

	Approved By Board Order[1]	Actual	Variance[2] Over (Under)
Energy Supply	$ 7,523	$ 7,520	$ (3)
Substations	7,347	5,986	(1,361)
Transmission	2,861	3,089	228
Distribution	27,188	30,966	3,778
General Property	1,420	715	(705)
Transportation	2,200	1,609	(591)
Telecommunications	502	343	(159)
Computing Equipment	6,298	5,074	(1,224)
General Expenses Capital	2,500	2,868	368
	$ 57,839	**$ 58,170**	**$ 331**
Carried Over to 2003	-	5,528	5,528
Adjusted for carryover to 2003	**$ 57,839**	**$ 63,698**	**$ 5,859**

[1] Order Nos. P.U. 21 (2001-2002) and P.U. 15 (2002-2003).

[2] Variance details are outlined in the 2002 Capital Expenditure Summary Report filed with the Board on Feb. 28, 2003.

Substations: The Salt Pond power transformer was budgeted for 2002; however, it could not be delivered until 2003. The positive variance associated with this was somewhat offset by increased costs associated with the Gander substation rebuild and the modifications at Wesleyville to accommodate the Gas turbine relocation.

Transmission: The increased costs in this category are associated with projects required in connection with re-establishing proper vertical clearances for transmission lines 100L, 124L and 146L.

Distribution: Extension projects associated with providing service to new customers cost more than anticipated due to the increase in the number of new residential customers being above forecast, as well as several unanticipated large extensions to service new commercial customers and cottage areas.

Reconstruction projects and transformer purchases also exceeded budget due mainly to lightening storms that were experienced throughout 2002.

General Property: The $750,000 allowance for unforeseen items was not required for expenditures in 2002.

Transportation: The decrease in this category was due to a delay in receiving the heavy vehicle order for 2002.

Telecommunications: The decrease in this category was due to a delay in the construction of fiber optic links planned for 2002.

Computing Equipment (Information Systems): The decrease in this category was due to a delay in the completion of the facilities management system to allow additional time to identify process improvements for inclusion in the system. As well there was a reduction and delay in the operating support system to determine if the facilities management system and the business support system could be used to address some of the requirements for that project.

General Expense Capital: The increase in this category was due to increased effort associated with the 2002 capital budget as well as increased expenditure associated with vacation, payroll and material overhead.

Newfoundland Power Inc.
Capital Expenditure Variance Summary
as of December 31, 2003
(000s)

	Approved By Board Order [1]	Forecast	Variance[2] Over (Under)
Energy Supply	$ 7,076	$ 7,429	$ 353
Substations	5.887	5,820	(67)
Transmission	4,129	4,291	162
Distribution	26,132	27,614	1,482
General Property	910	1,047	137
Transportation	2,141	2,328	187
Telecommunications	383	294	(89)
Computing Equipment	5,507	5,728	221
General Expenses Capital	2,800	2,800	0
Unforeseen Items	750	375	(375)
	$ 55,715	**$ 57,726**	**$ 2,011**
Carried Over from 2002	-	5,528	5,528
Adjusted for carryover from 2002	**$ 55,715**	**$ 63,254**	**$ 7,539**

[1] Order Nos. P.U. 36 (2002-2003), P.U. 19 (2003).

[2] Variance details are contained in 2003 Capital Expenditure Status Report which is filed with the 2004 Capital Budget Application

Newfoundland Power Inc.
Capital Budget Plan
($000s)

Category	**2004**	**2005**	**2006**	**2007**	**2008**
Energy Supply	$6,945	$4,429	$12,627	$5,382	$4,860
Substations	5,199	5,686	5,890	6,456	7,586
Transmission	2,315	6,899	5,592	6,231	6,195
Distribution	27,636	25,788	21,150	20,758	19,372
General Property	709	1,180	1,043	970	960
Transportation	3,487	2,831	2,354	2,283	2,408
Telecommunications	120	424	170	370	550
Information Systems	3,948	3,750	3,595	3,460	3,640
Unforeseen Items	750	750	750	750	750
General Expense Capital	2,800	2,800	2,800	2,800	2,800
Total	**$53,909**	**$54,537**	**$55,971**	**$49,460**	**$49,121**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

ENERGY SUPPLY

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Hydro Plants Facility Rehabilitation	$1,122	$3,013	$1,503	$4,092	$2,843
Hydro Plant – Penstock, & Pivot Valve Replacement	3,973	466	9,291	1,140	1,867
Purchase Portable Diesel Generation	1,700	0	0	0	0
Major Electrical Equipment Repairs	150	150	150	150	150
Thermal Plants Facility Rehabilitation	0	800	0	0	0
Hydro Plant – Surge Tank Replacement	0	0	1,683	0	0
Total - Energy Supply	**$6,945**	**$4,429**	**$12,627**	**$5,382**	**$4,860**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

SUBSTATIONS

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Rebuild Substations	$1,023	$550	$493	$1,436	$1,687
Replacement & Standby Substation Equipment	1,314	2,146	2,136	3,225	2,704
Transformer Cooling Refurbishment	398	250	250	250	250
Protection & Monitoring Improvements	80	45	45	45	45
Distribution System Feeder Remote Control	1,000	1,000	1,500	1,500	1,500
Feeder and Transformer Additions due to Growth and Reliability	1,384	344	1,466	0	1,400
New Line – Old Perlican to Victoria	0	1,351	0	0	0
Total – Substations	**$5,199**	**$5,686**	**$5,890**	**$6,456**	**$7,586**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

TRANSMISSION

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Rebuilt Transmission Lines	$2,315	$3,101	$5,592	$6,231	$6,195
New Line – Old Perlican to Victoria	0	3,798	0	0	0
Total – Transmission	**$2,315**	**$6,899**	**$5,592**	**$6,231**	**$6,195**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

DISTRIBUTION

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Extensions	$4,956	$4,680	$4,030	$3,696	$3,489
Meters	1,174	699	594	631	764
Services	1,946	2,099	1,754	1,724	1,755
Street Lighting	1,242	1,091	1,148	1,018	1,031
Transformers	4,965	4,600	4,400	4,250	4,110
Reconstruction	2,461	2,644	2,592	2,584	2,359
Aliant Pole Purchase	4,044	4,044	0	0	0
Trunk Feeders					
Rebuild Distribution Lines	4,137	4,051	5,037	5,505	4,704
Relocate/Replace Distribution Lines For Third Parties	235	235	235	235	235
Distribution Reliability Initiative	949	1,315	900	750	750
Feeder Additions and Upgrades to Accommodate Growth	677	230	360	265	75
Switch Replacement & Upgrade					
Underground Distribution – Water Street, St. John's	750	0	0	0	0
Interest During Construction	100	100	100	100	100
Total – Distribution	**$27,636**	**$25,788**	**$21,150**	**$20,758**	**$19,372**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

GENERAL PROPERTY

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Tools and Equipment	$535	$518	$425	$350	$350
Additions to Real Property	174	662	618	620	610
Total – General Property	**$709**	**$1,180**	**$1,043**	**$970**	**$960**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

TRANSPORTATION

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Purchase Vehicles and Aerial Devices	$3,487	$2,831	$2,354	$2,283	$2,408
Total – Transportation	**$3,487**	**$2,831**	**$2,354**	**$2,283**	**$2,408**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

TELECOMMUNICATIONS

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Replace/Upgrade Communications Equipment	$70	$70	$75	$46	$160
Substation Telephone Circuit Protection	50	90	95	99	103
Fibre Optic Networking	0	264	0	225	287
Total – Telecommunications	**$120**	**$424**	**$170**	**$370**	**$550**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

INFORMATION SYSTEMS

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Application Enhancements	$1,355	$1,390	$1,375	$1,075	$950
Application Environment	791	410	700	860	1,060
Customer Systems Replacement	226	250	170	175	175
Network Infrastructure	393	250	50	50	50
Personal Computer Infrastructure	539	550	550	550	555
Shared Server Infrastructure	644	900	750	750	850
Total – Information Systems	**$3,948**	**$3,750**	**$3,595**	**$3,460**	**$3,640**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

UNFORESEEN ITEMS

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total – Unforeseen	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2004 Capital Budget Plan
($000s)

GENERAL EXPENSE CAPITAL

Project	**2004**	**2005**	**2006**	**2007**	**2008**
Allowance for General Expense Capital	$2,800	$2,800	$2,800	$2,800	$2,800
Total – General Expense Capital	**$2,800**	**$2,800**	**$2,800**	**$2,800**	**$2,800**

Changes in Deferred Charges
2003 – 2004

Introduction

In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power (the "Company") to incorporate deferred charges in rate base commencing in 2003. In addition, the Board ordered that evidence relating to changes in deferred charges, in particular deferred pension costs, be filed annually with the Company's capital budget application.

The purpose of this report is to provide the evidence on changes in deferred charges ordered by the Board to be filed with the Company's 2004 capital budget.

Deferred Charges

Table 1 sets out the actual deferred charges for 2002 and forecast deferred charges for 2003 and 2004.

Table 1
Deferred Charges: 2002-2004F
($000s)

	Actual	Forecast	
	2002	**2003**	**2004**
Weather Normalization Account	10,919	9,705	8,579
Deferred Regulatory Costs & Other	16	816	416
Unamortized Debt Discount & Expense	3,490	3,290	3,092
Unamortized Capital Stock Issue Expense	458	392	325
Deferred Pension Costs	64,684	72,794	79,780
Total Deferred Charges	**79,567**	**86,997**	**92,192**

The forecast for deferred charges is consistent with that filed in the Company's 2003 General Rate Application, except for the Weather Normalization Account which has changed marginally due to the routine operation of this account up to May 31, 2003.

There are no changes in the forecast for Deferred Regulatory Costs & Other, Unamortized Debt Discount & Expense, Unamortized Capital Stock Issue Expense or Deferred Pension Cost from that presented in the Company's 2003 General Rate Application.

Weather Normalization Account

The Weather Normalization Account has been historically included as a component of rate base and as such the treatment of the Weather Normalization Account is unchanged by the inclusion of certain deferred charges in rate base as ordered by the Board in Order No. P.U. 19 (2003).

The balance in the Weather Normalization Account is comprised of two reserve accounts as described in Table 2.

Table 2
Weather Normalization Account: 2002-2004F
($000s)

	2002	**2003F**	**Change 2003F vs. 2002**	**2004F**	**Change 2004F vs. 2003F**
Hydro Production Equalization Reserve	9,551	8,467	(1,084)	7,341	(1,126)
Degree Day Normalization Reserve	1,368	1,238	(130)	1,238	0
Total	10,919	9,705	(1,214)	8,579	(1,126)

The functioning of these reserves is governed by Order No. P.U. 32 (1968) in the case of the Hydro Production Equalization Reserve and Order No. P.U. 1 (1974) in the case of the Degree Day Normalization Reserve. The combined balances in the Weather Normalization Account are provided annually to the Board in Return 14 for review and approval by the Board. Order No. P.U. 22 (2003) approved the balance in the Weather Normalization Account as of December 31, 2002.

In Order No. P.U. 19 (2003) the Board accepted Newfoundland Power's proposal to amortize the recovery of the $5.6 million non-reversing balance in the Hydro Production Equalization Reserve over a period of five years. The reduction in the Hydro Production Equalization Reserve of $1,126,000 in 2003 and 2004 is reflective of that amortization. The remaining change in the Hydro Production Equalization Reserve in 2003 relates to the actual operation of the reserve.

Both the Hydro Production Equalization Reserve and the Degree Day Normalization Reserve are affected by actual weather patterns compared to 'normal' weather patterns. As noted above, the difference between 'normal' weather and that actually experienced to the end of May 2003 has been reflected in the revised 2003 forecast.

Deferred Regulatory Costs & Other

The increase in deferred regulatory costs in 2003 and the subsequent decrease in 2004 reflects the incurrence of $1.2 million of hearing costs and their subsequent amortization over three years beginning in 2003 in accordance with Order No. P.U.19 (2003). This is set out in Table 3.

Table 3
Deferred Regulatory Costs: 2002-2004F
($000s)

	2002	2003F	Change 2003F vs. 2002	2004F	Change 2004F vs. 2003F
Deferred Regulatory Costs & Other	$16	816	$800	416	($400)

Unamortized Debt Discount and Capital Stock Issue Expenses

Changes in unamortized debt discount and capital stock issue expenses are set out in Table 4.

Table 4
Capital Issue Expenses: 2002-2004F
($000s)

	2002	2003F	Change 2003F vs. 2002	2004F	Change 2004F vs. 2003F
Unamortized Debt Discount & Expense	3,490	3,290	(200)	3,092	(198)
Unamortized Capital Stock Issue Expense	458	392	(66)	325	(67)

The decline in the Unamortized Debt Discount & Expense each year reflects the normal amortization of these costs over the life of each debt issue.

The decline in the Unamortized Capital Stock Issue Expense each year reflects the normal amortization of these costs over a 20-year period.

Deferred Pension Costs

The difference between *pension plan funding* and *pension plan expense* is captured as a *deferred pension cost* on the balance sheet in accordance with Order No. P.U.17 (1987).

Deferred pension costs are currently unchanged from that forecast in the Company's 2003 General Rate Application, and forecast 2003 – 2004 costs are set out in Table 5.

Table 5
Forecast Deferred Pension Costs: 2003-2004
($000s)

	2003F	**2004F**
Deferred pension costs, January 1st	64,684	72,794
Pension plan funding		
- Current service funding	3,350	3,501
- Special funding	7,589	6,384
Total pension plan funding	10,939	9,885
Pension plan expense	(2,829)	(2,899)
Increase in deferred pension costs	8,110	6,986
Deferred pension costs, December 31st	72,794	79,780

Pension plan funding is comprised of two components: current service funding which is determined by an independent actuary and is related to service rendered by active employees in the current year; and, special funding which are additional pension funding requirements to address increases in the unfunded liability in the pension plan since its inception. The status of the unfunded liability or surplus is determined each time an actuarial study is completed. Under pension legislation, this has to occur at least once every three years.

The Company calculates annual pension expense in accordance with recommendations of the Canadian Institute of Chartered Accountants ("CICA") and relevant Board orders, the most recent of which is Order No. P.U. 19 (2003).

The forecasting of pension plan funding and pension plan expense beyond 2003 is subject to changes based upon the following factors:

1. An actuarial valuation must be prepared and filed with pension regulators in 2004. Based on this valuation, the actuary will determine the appropriate current service funding for 2004 and the total unfunded pension liability.

2. The final pension plan expense for 2004 can only be determined early in 2004 once actual pension plan asset balances are known. This determination is made based on the December 31, 2003 market value of pension plan assets in accordance with CICA Handbook recommendations.

3. The discount rate that is required to be used under the CICA Handbook rules to calculate 2004 pension expense is the actual market rate of interest at December 31, 2003.

While pension plan funding and pension plan expense for 2004 is subject to change from the forecast provided above, both will be determined based on standards that have been consistently applied year over year, and which are in compliance with CICA recommendations, actuarial principles, and Board orders.

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

Prefiled Evidence of
Earl Ludlow and Phonse Delaney

NEWFOUNDLAND POWER
A FORTIS COMPANY

At the hearing into Newfoundland Power's 2004 Capital Budget Application, the following evidence will be adopted by Earl Ludlow, P. Eng., Vice President, Engineering & Operations of Newfoundland Power and Phonse Delaney, P. Eng., Manager Western Region, with Newfoundland Power.

A Witness profile for Earl Ludlow and Phonse Delaney follow.

Earl Ludlow, P.Eng.
Vice President, Engineering & Operations
Newfoundland Power Inc.

Earl Ludlow joined Newfoundland Power in 1980 as an Electrical Engineer.

Until 1994, Mr. Ludlow served Newfoundland Power in a variety of capacities including safety management for 2 years, materials management for 4 years and operations management for 7 years.

From 1995 to 1997, Mr. Ludlow served as Vice President, Operations of Maritime Electric Company Limited, Prince Edward Island.

In 1997, Mr. Ludlow was appointed Vice President, Operations of Newfoundland Power and, in 2001, was appointed Vice President, Engineering & Operations of Newfoundland Power.

Mr. Ludlow is currently a member of the *Canadian Electricity Association's* (CEA) Transmission Council and Distribution Council. He chairs CEA's Task Group on Metering & Regulations and is Past Chair of the Task Force on Regional Transmission Organizations.

Mr. Ludlow is an executive member of the Conference Board of Canada's Council for Performance Excellence.

Mr. Ludlow is a member of the Board of Regents of Memorial University. He also serves on the Engineering and Applied Science Advisory Council and is Chair of the Faculty Development Subcommittee.

Mr. Ludlow has testified before the Board of Commissioners of Public Utilities of Newfoundland and Labrador on matters relating to utility operations, capital expenditures, customer service and related costs.

Mr. Ludlow is a graduate of Memorial University (B.Eng. (Elec.) 1980; M.B.A. 1994) and is a member of the Association of Professional Engineers and Geoscientists of Newfoundland.

Phonse Delaney, P. Eng.
Manager, Western Region
Newfoundland Power Inc.

Phonse Delaney joined Newfoundland Power in 1987 as an Electrical Engineer.

Until 1999, Mr. Delaney served Newfoundland Power in a variety of operations and engineering capacities throughout the Company. Mr. Delaney has held the positions of Electrical Engineer - Stephenville, Planning Engineer - Head Office, Regional Planning Engineer - St. John’s, Superintendent of Operations - Burin, Superintendent of Engineering and Operations - Clarenville, Senior Operations Engineer - Head Office, Superintendent of Regional Engineering - St. John’s.

In 1999, Mr. Delaney was appointed Manager, Avalon Region. With the reorganization of regional operations in 2001, Mr. Delaney moved to Manager, Western Region.

Mr. Delaney is responsible for the engineering, operation and maintenance of Newfoundland Power’s electrical infrastructure in the Western Region and has corporate responsibilities for Automation, Telecommunications and Joint-Use.

Mr. Delaney is a graduate of Memorial University (B.Eng. (Elec.) 1986) and is a member of the Association of Professional Engineers and Geoscientists of Newfoundland.

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SUMMARY OF EVIDENCE

Newfoundland Power's 2004 proposed capital expenditures total $53,909,000. Approximately 56% of the proposed budget is allocated to replace deteriorated plant and equipment and approximately 22% is proposed to be spent to serve new customers and respond to third party requests.

Newfoundland Power's *2004 Capital Budget Plan* anticipates average annual capital expenditures of approximately $52 million over the period 2004 through 2008. Replacement of deteriorated defective or obsolete electrical equipment is forecast to account for approximately 60% of total expenditures through this period.

Newfoundland Power is currently forecasting that its 2003 capital expenditures will exceed the approved budget by 3.6%.

1. CAPITAL PLANNING

This section of the evidence briefly outlines how Newfoundland Power plans and executes its capital budget.

1.1 Planning Generally

Newfoundland Power's capital planning is a deliberate effort to balance customer needs, reliability, productivity, safety and environmental needs with prudent capital expenditures.

Planning begins with the customer and energy forecasts. These forecasts predict changes in the number of customers and energy usage by area. The customer forecast influences such budget items as distribution extensions, services, meters, street lighting, and transformers. The energy forecast in gigawatt-hours ("GWh"), along with the maximum demand in mega-volt amperes ("MVA") for each substation for the previous year, is used to determine load growth related expenditures in the Distribution, Substations and Transmission categories.

For all budget categories, projects are developed that reflect reliability, safety, customer service, environmental, and productivity requirements. The projects are identified either through visual and infrared thermoscan inspections, or through reviews of system reliability and equipment performance. During budget consultations, these budget items are reviewed, modified and prioritized, and an appropriate capital budget is proposed. This budget is presented to the Company's Board of Directors for corporate approval, and then to this Board for regulatory approval.

Annual capital expenditures are routinely reviewed to ensure that the circumstances and projections on which the capital plans were based have not changed. Should circumstances change, expenditures that are no longer required are cancelled or deferred and, when necessary, supplementary regulatory approval is sought for unforeseen requirements.

1.2 2004 Capital Budget Plan

In accordance with Order No. P.U. 36 (2002-2003) the Company has submitted a 2004 *Capital Budget Plan* (the "Plan") with the Application.

The Plan outlines a five year forecast for capital expenditures. The Company anticipates investing approximately $260 million in plant and equipment during the 2004 to 2008 period. The capital investment pattern outlined in the Plan is stable with an average annual budget throughout the 2004 to 2008 period of approximately $52 million. Consistent with the past five years, replacement of deteriorated, defective and obsolete electrical equipment will continue to dominate capital projects and account for approximately 60% of total expenditures or about $30 million per year. This amount is approximately the same as the depreciation expense incurred each year by the Company.

The Plan is based on a prioritized list of projects that are expected to be completed during the five year period. However, circumstances may change and as a result, priorities and levels of capital expenditures may also change.

For example, the Company is currently aware of a proposed mine site development in central Newfoundland that could result in transmission line expenditures in excess of $5,000,000 in 2005 and 2006. However, due to the uncertainty of this venture proceeding, expenditures are not included in the five year forecast.

2. 2004 CAPITAL BUDGET OVERVIEW

This section of the evidence provides an overview of the principal drivers behind Newfoundland Power's 2004 capital budget expenditures.

Schedule A to the Application, provides a summary of Newfoundland Power's 2004 proposed capital expenditures, which total $53,909,000, including general expenses capitalized. The justifications for the proposed 2004 capital expenditures are found in Schedule B to the Application.

Newfoundland Power has an obligation to serve new and existing customers in its service territory with a reliable electricity supply, consistent with reasonable cost. This is accomplished through capital expenditures to accommodate new customer and energy growth and third party requests, replacement of deteriorated equipment, additions to improve operating efficiency, and investments in information systems directed towards improving and maintaining overall productivity.

In 2004, approximately $12.0 million, or 22% of the budget, is proposed to be spent to serve new customers and third party requests; $30.1 million, or 56% of the budget, is allocated to replace deteriorated plant and equipment; $4.0 million, or 7% of the budget, relates to the Aliant pole purchase; and $3.9 million, or 7%, is proposed to be spent on information systems. The remaining $3.6 million is allocated to General Expenses Capital, Unforeseen Items, plant additions and Interest During Construction for small Distribution projects.

3. 2004 CAPITAL BUDGET SUMMARY BY BUDGET CATEGORY

This section of the evidence provides a summary of the principal proposed 2004 expenditures in each of the Energy Supply, Substations, Transmission, Distribution, General Property, Transportation, Telecommunication and Allowance for Unforeseen Items categories.

3.1 Energy Supply

Proposed Energy Supply expenditures in the 2004 capital budget are $6,945,000, or approximately 13% of the total budget. Details can be found at pages 10 to 17 of Schedule B to the Application.

Table 1 contains a summary of the proposed Energy Supply expenditures.

Table 1
2004 Capital Budget
Energy Supply
($000s)

Hydro Plant Facility Rehabilitation	$1,122,000
New Chelsea – Hydro Plant Refurbishment	3,973,000
Purchase Portable Diesel Generation	1,700,000
Major Electrical Equipment Repairs	150,000
	$6,945,000

Nine of the Company's 23 hydro plants will see rehabilitation work at a cost of $1,122,000 in 2004. While the Company's hydro plants are relatively small when viewed as stand-alone production centres, their total combined annual production is approximately 426 GWh, displacing over 700,000 barrels of oil. At $28 per barrel, this amounts to about $20 million in annual avoided fuel costs. These plants also contribute to system reliability and, in many cases, provide a source for local backup power.

A major project proposed in the 2004 capital budget involves refurbishment of equipment and the replacement of the deteriorated penstock at the New Chelsea plant in Trinity Bay at a cost of $3,973,000.

The 2.5 MW portable diesel generator proposed to be acquired at a cost of $1,700,000 will replace capacity that was lost when two existing portable generators and the St. John's diesel generator are decommissioned in 2003. In the winter, Newfoundland Power will station the new generation unit in Trepassey, which is an area currently served by a radial electrical system. The portability of this unit will provide additional flexibility for the Company during power restoration efforts, as it can be moved to areas that have suffered as a result of severe weather. It will also be used to maintain continuous service to customers during construction and maintenance activities that would otherwise require an outage.

3.2 Substations

Proposed Substations expenditures in the 2004 capital budget are $5,199,000 or approximately 10% of the total budget. Details can be found at pages 18 to 31 of Schedule B to the Application.

Table 2 contains a summary of the proposed Substations expenditures.

Table 2
2004 Capital Budget
Substations
($000s)

Rebuild Substations	$1,023,000
Replacement and Spare Substation Equipment	1,314,000
Transformer Cooling Refurbishment	398,000
Protection and Monitoring Improvements	80,000
Distribution System – Feeder Remote Control	1,000,000
Feeder Additions Due to Load Growth	200,000
Increase Corner Brook Transformer Capacity	1,184,000
	$5,199,000

The Rebuild Substations project includes the refurbishment or replacement of structures at 12 substations. The largest project, in the amount of $217,000, involves the replacement of 138 kV switches at the Port Blandford Substation. The work at these substations is required to maintain the reliability and continuity of service to customers and to eliminate potential safety hazards to employees.

In 2002, the Company initiated a program to replace a number of aging, limited function, electromechanical relays and oil-filled reclosers. By the end of 2003, over 40 relays and 30 reclosers will have been replaced. In 2004, approximately $1,000,000 is proposed to be spent to install 25 new relays and 6 new reclosers which can be remotely controlled by the System Control center. This will provide improved reliability to the customers serviced by the feeders involved in these changes.

The largest project in the Substations category relates to an increase in transformer capacity in the Corner Brook area. The project envisages installation of a new 25 MVA transformer at Walbournes Substation as a replacement for an existing 15 MVA unit, and then moving the existing 15 MVA transformer at Walbournes Substation to the Bayview Substation. This project is budgeted at a cost of $1,184,000, and is necessary to provide capacity to the system which is forecasted to be at 100% loading in the 2003/2004 winter season.

3.3 Transmission

Proposed Transmission expenditures in the 2004 capital budget are $2,315,000 or approximately 4% of the total budget. The proposed $2,315,000 expenditure will be used to rebuild transmission lines. Details can be found at pages 32 to 33 of Schedule B to the Application.

The Rebuild Transmission Lines project includes the proposed refurbishment of lines at a number of locations, eight of which are estimated to be in excess of $50,000 each. The project includes replacement of poles, crossarms, conductor, pin type and suspension insulators and other miscellaneous hardware. Two of the larger refurbishments included in these expenditures are $364,000 to rebuild a 4.7 km section of transmission line 3L from Goulds to Petty Harbour and $380,000 to rebuild a 5.1 km section of 403L from St. Georges to Lookout Brook. These expenditures are necessary to ensure the continued reliability of the Company's transmission lines.

3.4 Distribution

Proposed Distribution expenditures in the 2004 capital budget are $27,636,000 or approximately 51% of the total budget. Details can be found at pages 34 to 58 of Schedule B to the Application.

Table 3 contains a summary of the proposed Distribution expenditures.

Table 3
2004 Capital Budget
Distribution
($000s)

Extensions	$4,956,000
Meters	1,174,000
Services	1,946,000
Street Lighting	1,242,000
Transformers	4,965,000
Reconstruction	2,461,000
Aliant Pole Purchase	4,044,000
Trunk Feeders	6,748,000
Interest During Construction	100,000
	$27,636,000

The proposed expenditures for extensions, services, street lighting and transformers are primarily influenced by growth in the number of customers served by the Company. Budgeted expenditure levels are determined with reference to the Company's forecast of new customers using historical expenditures as a guide. In addition to the requirements for customer growth, the transformer account also includes units that are necessary to replace rusty or deteriorated units that have been identified through field inspections.

The expenditures for reconstruction are primarily focused on maintaining reliability and safety.

Proposed trunk feeder expenditures of approximately $6.7 million include large projects such as the distribution reliability initiative, the rebuild distribution line projects and the Water Street Underground Switch Replacement Project. The proposed expenditures are also primarily focused on reliability. In 2004, the distribution reliability initiative provides approximately $950,000 in capital expenditures for the New Wes Valley, Port de Grave and Torbay areas. The rebuild distribution line initiative provides approximately $4.1 million to perform refurbishment and replacement of structures and equipment on approximately 20% of the Company's 300 distribution feeders. Capital expenditures of $750,000 are provided to complete the Water Street Underground Switch Replacement Project which commenced five years ago.

Approximately $235,000 of the expenditures in the Distribution category is associated with the relocation of plant at the request of third parties. A significant portion of the cost is recovered from the parties making the requests.

3.5 General Property

Proposed General Property expenditures in the 2004 capital budget are $709,000 or just over 1% of the total budget. Details can be found at pages 59 to 61 of Schedule B to the Application.

Table 4 contains a summary of the proposed General Property expenditures.

Table 4
2004 Capital Budget
General Property
($000s)

Tools and Equipment	$535,000
Additions to Real Property	174,000
	$709,000

This category includes expenditures for the addition or replacement of tools and equipment utilized by line and support staff in the day-to-day operations of the Company, as well as the replacement or addition of office furniture and equipment. The Additions to Real Property project is necessary to maintain buildings and facilities and to operate them in an efficient manner.

3.6 Transportation

Proposed Transportation expenditures in the 2004 capital budget are $3,487,000 or approximately 6% of the total budget. Details can be found at pages 62 to 63 of Schedule B to the Application.

There are a number of factors that influence the purchase of new vehicles including kilometres travelled, vehicle condition, operating experience and projected operating expenditures.

In 2004, 36 units will be purchased, consisting of 15 passenger, 9 off-road, and 12 heavy fleet vehicles.

3.7 Telecommunications

Proposed Telecommunications expenditures in the 2004 capital budget are $120,000. Details can be found at pages 64 to 67 of Schedule B to the Application.

Table 5 contains a summary of the proposed Telecommunications expenditures.

Table 5
2004 Capital Budget
Telecommunications
($000s)

Replace/Upgrade Communications Equipment	$70,000
Substation Telephone Circuit Protection	50,000
	$120,000

3.8 Allowance for Unforeseen Items

This account is required to permit the Company to act expediously to deal with unexpected events affecting the electrical system for which funds have not been specifically budgeted.

In previous capital budget applications the Allowance for Unforeseen Items was included under the General Property category. In Order No. P.U. 36 (2002-2003) the Board directed Newfoundland Power to report budget, actual and forecast capital expenditures for Unforeseen Items separately.

The Allowance for Unforeseen Items in the 2004 Capital Budget is $750,000. Details can be found at page 80 of Schedule B to the Application.

4. 2003 CAPITAL EXPENDITURES

This section of the evidence provides an overview of variances from budgeted 2003 capital expenditures.

The approved 2003 capital budget, as well as the forecast of 2003 capital expenditures and resulting variances, is set out in detail, in the report entitled *2003 Capital Expenditure Status Report*, which is filed with the Company's 2004 Capital Budget Application.

Variances from budget in the capital expenditures of an electric utility are unavoidable. Because the intervening time between the completion of the budget process and the execution of capital projects can often exceed twelve months, unforeseen circumstances can alter capital requirements substantially. Should an emergency arise which poses a threat to safety or to Company operations, the Company must channel its resources to these areas and make the necessary adjustments to its capital plans. In any given year, the nature of the Newfoundland environment and the weather may also compel the Company to re-examine and refocus its capital plans.

The Distribution category is the largest component of the capital budget, and the number of individual variances is generally greatest in this area. In 2003, the demands placed on the Company for large service extensions to such locations at the Pitcher’s Pond Golf Course, the Cow Head industrial site and the Argentia Management Authority, as well as increased costs associated with certain reliability rebuild projects, resulted in increased expenditures of approximately $1.5 million.

Variances from initial cost estimates can also be caused by changes in the cost of materials and labour, or by unanticipated requirements associated with a project. For example, in Energy Supply, a project to refurbish the protection and controls on the mobile gas turbine was expanded to include refurbishment of the actual gas generator when detailed analysis identified the need for such work.

Capital expenditure variances may also result from changed circumstances revealed in ongoing reviews and reassessments of capital projects. For example, as a result of a review of certain substation projects, the requirements were reduced, and one project was deferred to 2004 due to the additional work associated with 2002 carryover projects.

Capital expenditures on Information Technology are forecasted to be $5,728,000 representing a variance of $221,000 over the initial budget of $5,507,000. The majority of this increase is associated with the cost of hardware and external resources necessary to upgrade the Unix operating system and application software associated with the System Control and Data Acquisition ("SCADA") system.

Overall, the Company is currently forecasting that its 2003 capital expenditures will exceed the approved budget by 3.6%.

The Company is always mindful of the possibility of changes in conditions and circumstances, and it continually reviews its capital program to ensure that only work that is necessary to achieve or maintain customer service objectives is included. If projects can be deferred or cancelled without affecting customer service, reliability or safety, the capital program will be adjusted accordingly. In the case of significant changes, the Company will seek approval of this Board.

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

Prefiled Evidence of
Michael Mulcahy and Peter Collins

NEWFOUNDLAND POWER
A FORTIS COMPANY

At the hearing into Newfoundland Power's 2004 Capital Budget Application, the following Evidence will be adopted by Michael Mulcahy, Vice President, Customer and Corporate Services of Newfoundland Power and Peter Collins, Manager, Information Services of Newfoundland Power.

A Witness profile for Michael Mulcahy and Peter Collins follow.

Michael Mulcahy
Vice President, Customer & Corporate Services
Newfoundland Power Inc.

Michael Mulcahy joined Newfoundland Power in 2003 as Vice-President, Customer and Corporate Services.

Prior to 2003, Mr. Mulcahy was Vice-President, Hospitality Services with Fortis Properties Corporation, St. John's, Newfoundland and Labrador. From 1993 to 1996, Mr. Mulcahy served as Manager, Human Resources of Maritime Electric Company, Limited. Prior to joining Maritime Electric Company, Limited, Mr. Mulcahy held a variety of positions with Moosehead Breweries Limited in Dartmouth, Nova Scotia.

Mr. Mulcahy is a member of the Canadian Electricity Association's (CEA) Customer Council.

Mr. Mulcahy is a graduate of Dalhousie University (Bachelor of Commerce).

Peter Collins
Manager, Information Systems
Newfoundland Power Inc.

Peter Collins was appointed Manager, Information Systems, in 2001. In this position, he is responsible for all of Newfoundland Power's information technology infrastructure, applications, security, and the SCADA computer system.

Mr. Collins joined Newfoundland Power in 1986 as a Programmer Analyst and has served in progressively senior technology positions within the Company since that time.

Mr. Collins testified before the Board of Commissioners of Public Utilities of Newfoundland and Labrador during the Company's 2002 and 2003 Capital Budget hearing on matters relating to information technology capital expenditures.

Mr. Collins is a graduate of Memorial University (B. Sc. (Computer Science and Mathematics) 1985).

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SUMMARY OF EVIDENCE

Information technology plays an integral part in the provision of least cost, reliable and efficient service to Newfoundland Power's customers. It is at the core of the Company's interaction with its customers and is central to the maintenance and improvement of the Company's operating efficiency.

The strategic direction of information technology investment at Newfoundland Power has not changed materially since 1999. The Company will continue to focus its information technology investment in areas which improve customer service or operating efficiency.

The Company's Customer Service System is a critical computer application. It is the most prominent technology obsolescence issue currently facing Newfoundland Power. It is currently expected to remain in service until at least 2008.

Newfoundland Power's proposed 2004 capital budget for Information Systems is approximately $3.9 million or 7% of the Company's total capital budget.

1. INFORMATION TECHNOLOGY AT NEWFOUNDLAND POWER

This section of the evidence outlines the integral role played by information technology in the least cost provision of service by Newfoundland Power.

Information technology ("IT") is at the core of Newfoundland Power's interaction with its customers. IT plays an integral part in the provision of least cost, reliable and efficient service to Newfoundland Power's customers.

Most of the Company's interaction with its customers involves the use of IT. Agents in the Customer Contact Centre respond to customer inquiries using computer applications such as the outage system, the street light system, the meter system, and the intranet system. These applications reside on the Company's servers and network and are integrated with the Customer Service System ("CSS"), which contains virtually all of the information required to serve the Company's 220,000 customers.

Technology provides customers with flexibility in how they choose to interact with the Company. Using a telephone, customers can retrieve information about their billing account using the Company's call centre technology. Customers with access to the Internet can also retrieve account information, open and close their accounts, view their electrical consumption history, or join a payment plan without having to speak to an agent. These service options provide improvements in customer service while allowing the Company to reduce operating costs.

IT also contributes to the provision of reliable electrical service to customers. The increase in the use of technology in the electrical distribution system contributes to improved reliability. When a power outage occurs, the System Control Centre ("SCC"), through the technology installed in specific areas of the electrical distribution system, is notified immediately. Using IT, the SCC can, in many cases, remotely operate the distribution system to restore power. This responsiveness improves reliability and contributes to public and employee safety.

Properly maintained electrical assets are important for the provision of reliable electrical service to customers, particularly on a mature system. Using asset management technology, the Company is able to track its inspection and maintenance activities on its critical assets. These maintenance activities help to extend the lives of the assets, increase their reliability, and reduce costs.

Through the use of IT, the Company has made many significant gains in customer service, productivity, and reliability. Ongoing IT investment by the Company is vital to maintaining the gains already achieved through the use of technology. As well, ongoing investment is essential to making further improvement in customer service and operating efficiency.

2. INFORMATION TECHNOLOGY STRATEGY

This section of the evidence reviews the role, importance and direction of Newfoundland Power's capital investment in information technology.

The Information Systems category of the Company's annual capital budget contains projects that introduce further improvements in customer service, and operational efficiency. As well, this category contains projects that are designed to ensure that the improvements that have already been realized in operational efficiency and customer service through investment in information technology are sustained.

In Order P.U. 36 (2002-2003), the Board of Commissioners of Public Utilities (“the Board”) directed Newfoundland Power to prepare an updated Information Technology Strategy Report for the period 2004-2008 as part of its 2004 budget application. The *Information Technology Strategy 2004 - 2008* (the “Strategy Report”) was filed with the Company’s 2004 Capital Budget Application (the “Application”).

2.1 Information Technology Strategy

As outlined in the Strategy Report, the Company’s strategy is to align its IT investment with the imperatives of operating efficiency and customer service. This strategy is accomplished by making informed choices from among the variety of technologies that are available, and by effectively managing the installed technologies throughout their useful life.

Newfoundland Power has made considerable investment in IT applications and infrastructure to enhance customer service, to improve the reliability of its electrical distribution system, to improve public and employee safety, and to increase its overall operational efficiency. Over the course of the next five years, Newfoundland Power plans to make further improvements by investing more in the technologies already deployed throughout the Company, and less in the introduction of new applications. Also, the Company will continue to focus on extending the life of its technology infrastructure to the extent possible, without jeopardizing the gains that have already been achieved.

2.2 Managing the Investment

The full benefits of IT can only be realized when effective choices are made from the variety of options available, and when the technology is effectively managed over its life cycle. To accomplish this, Newfoundland Power takes a conservative approach to its technology investment decisions, waiting until a technology matures and becomes widely used and supported by industry leaders.

The rapid pace of change is a defining characteristic that permeates all aspects of IT. As technology vendors adapt or retire existing technology products to keep pace with the evolving expectations and business requirements of their customers, support for older products becomes more expensive and increasingly difficult to find. Obsolescence is an ever-present challenge to cost management for IT.

The principal issue concerning Newfoundland Power in relation to the obsolescence of IT involves the OpenVMS operating system. The Company has been monitoring this issue for a number of years.

The normal upgrade and replacement of computer applications over the course of the last few years has substantially mitigated the risks to the Company associated with the OpenVMS system. In 2003, the Company undertook a study to re-assess the issue of OpenVMS obsolescence given the recent mitigated risks, and to look at options for replacing or moving its most complex OpenVMS dependent application, the CSS.

In July 2003, the Company completed the *Customer Service System Replacement Analysis*, which is provided in Volume IV, Information Systems, Appendix 3 to the Application. This analysis involved consultation with technology and utility industry experts such as the Gartner Group[1] and the META Group[2], a review of utility industry publications, and consultation with leading technology suppliers such as Microsoft and Hewlett Packard. From this analysis, the Company concluded that the OpenVMS operating system continues to be in decline and preparations for the eventual replacement of the CSS should proceed. However, since Hewlett Packard purchased the OpenVMS system through its acquisition of Compaq Computer Corporation a year ago, they have introduced a degree of stability to the product and will continue to sell it to businesses at least until 2006, and will provide support until 2011.

Currently, the CSS substantially satisfies the Company's customer service needs. It is stable and reliable and there is a commitment for support of OpenVMS by suppliers. Given this, the Company currently expects it will continue to use the CSS on the OpenVMS operating system until at least 2008.

Another assessment of the OpenVMS obsolescence issue and the CSS replacement options is planned for 2006 to determine if current levels of industry commitment remain.

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand technology and drive business growth. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 80 locations worldwide.

[2] META Group is a research and advisory firm that helps more than 3,300 businesses in 40 countries understand technology and drive business growth. Unlike Gartner and other advisory firms, META Group also provides vertical expertise and coverage of the IT solutions for industries such as energy and utilities.

Going forward, the Company will look for opportunities to make the CSS less dependent on the OpenVMS operating system by utilizing non-OpenVMS technologies during the normal course of enhancements. The benefit of this approach will be to reduce the cost and complexity of the replacement of the CSS whenever that occurs and, as well, provide a measure of protection against risk of failure in the interim.

3. 2004 CAPITAL EXPENDITURES

This section of the evidence provides a summary of the principal proposed 2004 expenditures in the Information Systems category.

The Company proposes Information Systems expenditures in the 2004 capital budget of $3,948,000, or approximately 7% of the total capital budget. These expenditures are summarized at page 8 of Schedule B to the Application. Proposed expenditures in the Information Systems capital budget are categorized as either Computer Applications or Computing Infrastructure.

3.1 Computer Applications

The Computer Applications component of the Company's Information Systems capital budget consists of a range of technology tools and software in three different areas that support business processes. The three Computer Applications projects represent approximately 60% of the total proposed Information Systems capital budget.

3.1.1 Application Enhancements

Expenditures on Application Enhancements in 2004 will total $1,355,000. This will involve enhancements to some of the approximately 30 business applications. These enhancements are intended to increase efficiencies and enhance customer service while maintaining productivity.

This expenditure is in keeping with the Company's strategy of improving upon the existing installed information technology.

Details regarding Application Enhancements are provided at page 68 of Schedule B to the Application.

3.1.2 Application Environment

A total of $791,000 will be expended on this project in 2004. It includes upgrades to the software application Microsoft Great Plains that is used by for the financial, human resources, and materials management sections of the Company. The asset management application will also be upgraded. This application is used by operations & engineering staff to manage maintenance on substation and generation equipment. Properly maintained assets are a key to a reliable, least cost supply of electricity to customers. Also included are upgrades to software used to develop and test computer applications before they are implemented throughout the Company. Such software is used to ensure new versions of applications will work properly with existing applications, thus avoiding unnecessary downtime when putting new applications into operation.

Details regarding Application Environment are provided in at page 70 of Schedule B to the Application.

3.1.3 Customer Systems Replacement

As outlined in the *Customer Service System Replacement Analysis* provided in Volume IV, Information Systems, Appendix 3 to the Application, the Company will complete customer service and efficiency enhancements to the CSS that will also reduce its dependence on the

OpenVMS system. In 2004, improved customer bill design and printing capability will be implemented that will provide a more readable bill statement for customers. This improvement will also reduce the reliance on OpenVMS through the elimination of programming code.

Details regarding Customer Systems Replacement are provided at page 72 to the Application.

3.2 Computing Infrastructure

The Company's computing infrastructure consists of a variety of computer hardware, including personal computers, printers, shared servers, and shared network infrastructure. In 2004, the three Computing Infrastructure projects account for approximately 40% of the total Information Systems capital budget.

3.2.1 Network Infrastructure

The 2004 budget includes a proposed expenditure of $393,000 for the Network Infrastructure project. This is the second year of a two-year project that was approved in 2003. For 2004, this project involves the replacement of network equipment that is no longer manufactured and for which software upgrades are unavailable.

Details regarding Network Infrastructure are provided at page 74 of Schedule B to the Application.

3.2.2 Personal Computer Infrastructure

The Personal Computer Infrastructure project covers the replacement and upgrade of personal computers (PCs) and peripheral devices such as scanners and printers. To maximize the life of PCs, Newfoundland Power "cascades" older, less powerful, computers to employees with lesser capacity requirements while newer computers are assigned to those who have the most demanding requirements. The oldest, least reliable systems are retired. This ensures computer requirements are met, while keeping costs to a minimum. The planned expenditure in this category for 2004 totals $539,000.

Detail regarding Personal Computer Infrastructure are provided at page 76 of Schedule B of the Application.

3.2.3 Shared Servers Infrastructure

The proposed expenditure for the Shared Servers Infrastructure project in 2004 is $644,000. This project involves the purchase of additional and replacement shared servers, and the upgrade of existing server infrastructure to maintain current performance. Also included is the purchase of monitoring and security software to ensure the continued integrity and availability of the Company's computer systems.

Details regarding Shared Server Infrastructure are provided at page 78 of Schedule B to the Application.

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and
(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

Prefiled Evidence of
Barry Perry and Lisa Hutchens

NEWFOUNDLAND POWER
A FORTIS COMPANY

At the hearing into Newfoundland Power's 2004 Capital Budget Application, the following Evidence will be adopted by Barry Perry, C.A., Vice President, Finance & Chief Financial Officer of Newfoundland Power and Lisa Hutchens, C.A., Manager, Finance of Newfoundland Power.

Witness profiles for Barry Perry and Lisa Hutchens follow.

Barry Perry, C.A.
Vice President, Finance & Chief Financial Officer
Newfoundland Power Inc.

Barry Perry joined Newfoundland Power in 2000 as Vice President, Finance and Chief Financial Officer.

Prior to 2000, Mr. Perry was Vice President-Treasurer with Abitibi-Consolidated Inc. (Abitibi), Quebec. Mr. Perry commenced employment with Abitibi as Chief Financial Officer of the Company's International Business Unit which included the two newsprint mills and woodland operations located in Newfoundland. Mr. Perry has also served as Director, Financial Reporting for Abitibi.

Prior to joining Abitibi-Consolidated Inc., Mr. Perry was Corporate Controller of Newfoundland Processing Inc., the owner/operator of the Come by Chance Oil Refinery.

Mr. Perry obtained his Chartered Accountant designation while working with Ernst & Young Chartered Accountants in St. John's, Newfoundland.

Mr. Perry has testified before the Board of Commissioners of Public Utilities of Newfoundland and Labrador on several occasions in his capacity as Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

Mr. Perry is a graduate of Memorial University of Newfoundland (Bachelor of Commerce (Honours), 1986) and is a member of the Institute of Chartered Accountants of Newfoundland.

Lisa Hutchens, C.A.
Manager, Finance
Newfoundland Power Inc.

Lisa Hutchens has served as Manager, Finance of Newfoundland Power Inc. since 1997.

Prior to 1997, Ms. Hutchens was a Senior Manager with Deloitte and Touche, and held various positions within that firm in both St. John's and Halifax.

Ms. Hutchens obtained her Chartered Accountant designation while working with Deloitte & Touche, Chartered Accountants in St. John's, Newfoundland.

Ms. Hutchens is a graduate of Memorial University of Newfoundland (Bachelor of Commerce (Honours), 1987) and is a member of the Institute of Chartered Accountants of Newfoundland.

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SUMMARY OF EVIDENCE

For the purpose of regulatory continuity, Newfoundland Power is requesting that the Board approve its 2002 average rate base in the amount of $573,337,000.

Pursuant to Order No. P.U. 19 (2003), Newfoundland Power was required to move towards the adoption of the Asset Rate Base method of determining rate base. As a first step to moving to the Asset Rate Base Method the Company has included deferred charges in its rate base beginning in 2003.

As part of its 2004 capital budget application, the Company has provided evidence related to the changes in its deferred charges for 2003 and 2004.

In addition, a reconciliation of the differences between the Company's rate base and invested capital has been provided in accordance with Order No. P.U. 19 (2003). The 2004 capital budget will be financed by internally generated funds and short-term debt.

1. 2002 RATE BASE

Newfoundland Power's rate base is a cornerstone of the Board's regulation of the Company. For the purposes of regulatory continuity, as part of its capital budget presentation, Newfoundland Power seeks approval of its prior year's rate base.

Rate base, which is principally comprised of the Company's fixed assets, forms the basis of regulation of Newfoundland Power's returns.

Schedule D to the Application shows the average rate base for 2001 and 2002. The 2001 average rate base of $545,162,000 was approved by the Board in Order No. P.U. 36 (2002-2003). The average rate base for 2002 is $573,337,000, as filed with the Board on March 31, 2003 in Return 3 of the Company's 2002 Annual Return.

Changes to the Company's rate base are principally the result of two factors – capital expenditures and depreciation. Capital expenditures increase the rate base while depreciation expense decreases the rate base. When annual capital expenditures exceed annual depreciation, the rate base increases.

Schedule D to the Application shows plant investment as the starting point for the calculation of rate base. The increase in the Company's average rate base from 2001 to 2002 is primarily due to increases in plant investment. The increase in plant investment is a direct result of the Company's 2002 capital expenditures approved by the Board in Order Nos. P.U. 21 (2001-2002), and P.U. 15 (2002-2003).

The other significant variable impacting the average rate base is annual depreciation expense. Each year, annual depreciation expense is calculated using the composite rates approved by the Board. The depreciation rates in effect for 2002 were those approved by the Board in Order No. P.U. 7 (1996-97).

2. ASSET RATE BASE METHOD

This section of the evidence reviews the reconciling items between the Company's average invested capital and average rate base.

In Order No. P.U. 19 (2003) the Board approved a move toward the adoption of the Asset Rate Base method of determining rate base, and ordered the inclusion of deferred charges in the Company's rate base beginning in 2003.

Exhibit BVP-1 shows the calculation of actual average rate base for 2002 and the forecast average rate base for 2003 and 2004. The forecast average rate base for 2003 and 2004 includes deferred charges as ordered in Order No. P.U. 19 (2003).

With deferred charges included in rate base beginning in 2003, the most significant difference between the Company's rate base and its invested capital has been removed. However, there are still some remaining differences. The forecast differences between average invested capital and average rate base for 2003 and 2004 are reconciled in Table 1 below. None of the reconciling items have materially changed from those presented in the Company's 2003 General Rate Application.

Table 1
Reconciliation of Invested Capital to Rate Base
($000s)

	2003 Forecast	2004 Forecast
Average Invested Capital	670,283	705,996
Average Rate Base[1]	674,464	709,066
Difference	(4,181)	(3,070)
Reconciliation of remaining differences:		
Plant (primarily construction in progress)	2,395	1,835
Corporate Income Tax Deposit	6,949	6,949
Materials and Supplies (actual vs. allowance)	868	773
Working Capital (actual vs. allowance)	(22,371)	(21,330)
Common Equity (book vs. regulated)	7,978	8,703
	(4,181)	(3,070)

[1] Exhibit BVP-1.

The Company intends to review the appropriateness and approach to including these remaining reconciling items in its rate base in its next general rate application, in compliance with Order No. P.U. 19 (2003).

3. DEFERRED CHARGES

This section of the evidence provides information relating to the changes in the Company's deferred charges.

With the inclusion of certain deferred charges in the Company's rate base beginning in 2003, it is appropriate to review the forecast changes in the Company's deferred charges on a prospective basis.

The report entitled *Changes in Deferred Charges 2003 - 2004* (the "Report"), filed with the Application, presents a summary of the changes in the Company's forecast deferred charges for 2003 and 2004. The Report provides a description of all changes in the balances of the components of deferred charges from year to year The only difference in the information contained in the Report and that presented in the Company's 2003 General Rate Application relates to the routine operation of the Weather Normalization Account.

The Company's deferred pension costs are the largest component of both the deferred charges and the change in deferred charges from year to year. Deferred pension costs are the cumulative difference between the Company's pension funding and pension expense, and is captured on the balance sheet in accordance with Order No. P.U. 17 (1987).

Pension expense is determined based on recommendations of the Canadian Institute of Chartered Accountants (CICA) as outlined in the CICA Handbook Section 3461. *Pension funding* is determined in consultation with the Company's actuary and is comprised of current service funding and special funding. Further details on the determination of both pension expense and pension funding are provided in the Report.

Forecast deferred pension costs for 2003 and 2004 have not changed from the forecast presented to the Board in the Company's 2003 General Rate Application. After December 31, 2003 certain determinants of pension funding and pension expense will be reviewed in accordance with pension legislation (for determining pension funding) and CICA recommendations (for determining pension expense). Pension expense and pension funding amounts for 2004 will be subject to change based upon the results of these determinations.

The Company anticipates presenting evidence on changes to 2004 pension funding and pension expense which materially impact deferred pension costs to the Board at the Company's 2005 Capital Budget Application.

4. FINANCING 2004 CAPITAL EXPENDITURES

This section of the evidence outlines Newfoundland Power's current plans for financing its 2004 capital budget.

In general, the funds required to finance the Company's capital program come externally from the issue of debt and internally from generated cash flow. The Company's cash flow is derived from internally generated funds including net income, those expenses on the income statement that do not require an outlay of cash (e.g. depreciation) and changes in working capital.

Internally generated cash flow and short term debt are utilized until short term borrowing requirements approach a level where the Company considers a long term debt financing to be appropriate. The Company monitors capital markets to assess the appropriate timing of long term debt issues.

In late October 2002, Newfoundland Power closed the issue of $75,000,000 Series AJ First Mortgage Sinking Fund Bonds. The Company currently does not forecast another long term debt issue until after 2004. Until Newfoundland Power issues further long term debt, capital expenditures will be financed through internally generated funds and short term debt.

Newfoundland Power Inc.
2004 Capital Budget

Average Rate Base
(000s)

	2002	2003	2004
	Actual	Forecast	
Plant Investment	$1,005,674	$1,065,372	$1,104,886
Deduct:			
Accumulated Depreciation	420,736	445,073	461,003
Contributions in Aid of Construction	19,788	20,092	20,407
Deferred Income Taxes	-	1,269	2,038
Weather Normalization Reserve	(10,919)	(9,705)	(8,579)
	429,605	456,729	474,869
	576,069	608,643	630,017
Add – Contributions Country Homes	570	570	570
Balance – Current Year	576,639	609,213	630,587
Balance – Previous Year	553,586	576,639	609,213
Average	565,113	592,926	619,900
Cash Working Capital Allowance	4,712	4,973	5,036
Materials and Supplies	3,512	3,595	3,677
Average Rate Base at Year End	$573,337	$601,494	$628,613
Forecast Average Deferred Charges[1]		72,970	80,453
Revised Forecast Average Rate Base[2]		$674,464	$709,066

[1] Commencing in 2003, average deferred charges are included in average rate base as per Order No. P.U. 19 (2003).

[2] Forecast average rate base for 2003 and 2004 includes average deferred charges.

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2004 Capital Budget Application
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Changes in Deferred Charges 2003 - 2004

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Prefiled Evidence: Mulcahy / Collins

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Volume IV
Expenditure Details, Reports and Studies

Information Systems

Project Title: **Hydro Plant Facility Rehabilitation**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$1,122,000**

This project consists of a number of items as noted.

(a) Pierre's Brook – Replace Forebay Head Gate

Cost: $91,000

Description: Replace the existing head gate, gate guides and lift at the forebay intake structure including rehabilitation of the upstream stop log guides.

Operating Experience: Misaligned gate guides and water leakage around the head gate seals have rendered this structure ineffective in providing the positive water shut off required to perform maintenance and inspections of downstream facilities. An attempt to dewater the penstock in September 2002 proved unsuccessful and the subsequent binding of the gate in the misaligned guides prevented the operation of the plant for three days. The services of a diving contractor were required to open the gate. This structure is the original head gate installed when the project was commissioned in 1931.

Justification: The head gate is a critical link in the continued safe and effective operation and maintenance of the Pierre's Brook Hydro Generator. Normal production at the Pierre's Brook hydro facility is 25.3 GWh per year.

(b) Topsail – Replace Protection and Controls

Cost: $200,000

Description: Replace the existing governor controls and protection with Newfoundland Power's standard design Unit Control Panel, including a Programmable Logic Controller, generator protection, digital voltage regulation, synchronizer and metering.

Operating Experience: Newfoundland Power has an approved 2003 capital project to replace the electronic control portion of the Voest-Alpine governor system at Topsail Plant. The governor was installed by Barber Hydraulic Turbine in 1983 as part of a major plant refurbishment replacing turbine, generator, switchgear, protection and control systems. Originally the unit had difficulty synchronizing to the power system and in 1995 a modification was designed that involved filtering the output of the electronic controller with a programmable logic controller. Original equipment manufacturer ("OEM") support for the system is no longer available and the supply of spare parts has been exhausted. Newfoundland Power has undertaken to repair electronic boards in house for the equipment, however, repairing the electronics has become increasingly difficult as the discrete components and integrated circuits are no longer being manufactured.

The project for 2003 involves the replacement of the function provided by the electronic governor with a similar function relocated to the programmable logic controller (PLC) system. Detailed engineering design began early in 2003 for this project during which it became evident that the existing PLC equipment cannot support the complete governor function, and as a result, additional PLC hardware is required.

During the design phase, a review of the plant operators log identified that most of the 115 unscheduled plant outages were related to protection and control system failures. The inability to filter out transient losses of the speed signal and the instantaneous spiking of the bearing oil and temperature readings accounted for 42% of unit trips over the previous five years. The control of the pressure relief valve accounted for another 17% of unit trips and created another significant design issue to be addressed.

In order to address the problems noted above the scope of the necessary work has significantly expanded, making it impossible to complete the project within the original $230,000 budget. Therefore a decision has been made to carry over the original project to 2004 as a part of a larger project to complete the overall work. The combined budget for the larger project is $430,000.

Justification: Normal production at the Topsail plant is 14.2 GWh of energy annually. The governor is a critical system and the generator cannot be operated without it. Therefore, to ensure the reliable production of energy from this facility the equipment must be replaced. See Attachment A, Engineering Review – Topsail Plant Governor, Protection and Control System.

(c) Morris – Replace Turbine Runner Seals

Cost: $107,000

Description: Replace the mild carbon steel turbine runner stationary seals with either Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminum-bronze alloy stationary seals.

Operating Experience: The Morris turbine was installed as a new plant in 1983 by Barber Hydraulic Turbines. The turbine is a horizontal Francis Turbine. In April 2000, operators started to experience problems with the wicket gate operating ring jamming and acting sluggishly. The turbine was inspected and it was found that the carbon steel stationary seals had corroded, rust had accumulated, the two ends of the wicket gates were getting jammed in between the two stationary seals and the seals were in need of replacement.

Justification: Normal production at the Morris plant is 7.2 GWh of energy annually. The turbine runner stationary seals are critical to the operation of the plant. Therefore, to ensure the reliable production of energy from this facility, the equipment must be replaced. See Attachment B, *Morris Plant Turbine & Stationary Seal Inspection*.

(d) Rattling Brook – Rewind Generator G1

Cost: $407,000

Description: Rewind the stator coils in generating unit G1. This involves the disassembly of the generator, the removal of the stator winding, transport to a facility equipped for the work, transport back to site, installation and realignment.

Operating Experience: In 2002 the generator winding in unit G2 failed during a full load rejection. Testing revealed that a turn-to-turn fault had developed in the windings and a complete rewind of the stator was required. Unit G1 is identical in construction to unit G2, and over its forty-five year life has been exposed to a similar operating environment. Concern exists for the condition of generator windings on generators such as G1 that have exceeded their estimated life expectancy as established by the Institute of Electrical and Electronic Engineers (IEEE).

Justification: Rattling Brook generating station is an important source of energy to the Province, with normal hydro production of 69.4 GWh annually. This is Newfoundland Power's largest producing plant. There are times during the year when water flows are such that both generating units are required. An unplanned outage due to the loss of the generator winding on G1 would result in the loss of energy over the period necessary to effect the repair.

(e) Various Plants – Replace Cooling Coils

Cost: $69,000

Description: Replace bearing cooling coils and install bearing oil level controls and bearing cooling water flowmeters and controls. In 2004 cooling coils will be replaced in Rocky Pond, Rattling Brook, Cape Broyle and Pierre's Brook.

Operating Experience: Since 1997 we have experienced seven cooling coil failures which resulted in oil spills and lost production. The latest was in 2002 at Horse Chops plant.

Justification: This project will reduce the risk of bearing failures due to lubricant contamination and will also reduce the risk of hydrocarbon spills to the environment from these hydroelectric plants.

(f) Various Plants – Upgrade Protection and Controls

Cost: $200,000

Description: Replace protection and control systems in Newfoundland Power's hydro plants in order to improve the efficiency, reliability, safety and environmental aspects of the plants. This will be achieved by addressing issues pertaining to equipment that requires maintenance and is no longer supported by the manufacturers which makes replacement parts expensive or unavailable. As well, this project will improve the control and protection of the equipment by using more versatile electronic devices. Additional monitoring, control and protective devices will be installed to meet present day standards. These upgrades will also facilitate increased automation and remote control capabilities. In 2004 upgrades will take place at the following Hydro Plants: Rocky Pond, Rattling Brook, Fall Pond, Pittman Pond, Victoria and Morris.

Operating Experience: The power plants belonging to Newfoundland Power range in age from 5 to 103 years. Much of the original protection and control equipment is still in service, in particular the hydraulic gateshaft governors, switchgear and protective relays. The switchgear in some plants is over fifty years old and the majority of plants have protection schemes utilizing electromechanical relays that do not provide the present IEEE minimum protection requirements. Failure of these components is one of the main reasons for the outages at these hydro plants in 2002.

Justification: The continued efficient, reliable, safe and environmentally responsible operation of Newfoundland Power's generating stations requires the replacement of equipment which has gone beyond its serviceable life as well as the application of new technology to better monitor and control the units to minimize the possibility of costly, major failures.

(g) Projects < $50,000

Cost: $48,000

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

1. Hearts Content – Replace damaged concrete headwall at intake structure
2. Victoria – Replace corroded trashrack at intake structure

Topsail Plant
Governor, Protection and Control Systems
Engineering Review

Newfoundland Power Inc.

May 16, 2003

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Appendix A – Topsail Plant Operators Log

Introduction

Newfoundland Power has an approved 2003 capital project to replace the electronic control portion of the Voest-Alpine governor system at Topsail Plant. The governor was installed by Barber Hydraulic Turbine in 1983 as part of a major plant refurbishment project replacing turbine, generator, switchgear, protection and control systems.

The project for 2003 involves the replacement of the function currently provided by the electronic governor with a similar function located in the programmable logic controller (PLC) system. Detailed engineering design began early in 2003 for this project during which it became evident that the existing PLC equipment could not support the complete governor function. As a result, additional PLC hardware is required.

A review of the plant operators' log identified that most of the unscheduled plant outages were related to protection and control system failures (See Appendix A). The inability to filter out transient losses of the speed signal and instantaneous spiking of the bearing oil and temperature readings accounted for 42% of unit trips over the previous five years. The control of the pressure relief valve accounted for another 17% of unit trips and introduced another significant design issue to be addressed.

As a result, the scope of work has significantly expanded, thereby making it impossible to complete the project within the original $230,000 budget. Therefore a decision must be made as to whether the project will proceed in 2003 or an expanded project be submitted for the 2004 capital budget.

Normal production at the Topsail plant is 14.2 GWh of energy annually. The governor, protection and control systems are critical systems in the operation of the plant. Therefore, to ensure the reliable production of energy from this facility it is recommended that this project proceed as described in the Recommendation in 2004.

Technical Analysis

The following technical analysis has been completed on the governor, protection and control systems at Topsail plant.

Electronic Governor

The existing governor and control system at Topsail Plant was installed in 1983. Newfoundland Power has modified the equipment in order that satisfactory performance can be achieved from the plant. The synchronizing system requires frequent adjustment to maintain operational status as demonstrated in the operators' log provided in Appendix A. As a result, the synchronizing and governor systems are two of the most frequent causes of unscheduled outages for the plant. Originally, the unit had difficulty synchronizing to the power system and in 1995 Newfoundland Power designed a modification that involved filtering the output of the electronic governor controller with a PLC.

Original equipment manufacturer (OEM) support for the system is no longer available and the supply of spare parts has been exhausted. Newfoundland Power has undertaken to repair electronic boards in house for the Voest-Alpine equipment. However, repairing the electronics has become increasingly more difficult as the discrete components and integrated circuits are no longer being manufactured. Therefore, a solution is sought that involves replacing the proprietary hardware with standard PLC based technology consistent with installations in Newfoundland Power's other plants.

Protection

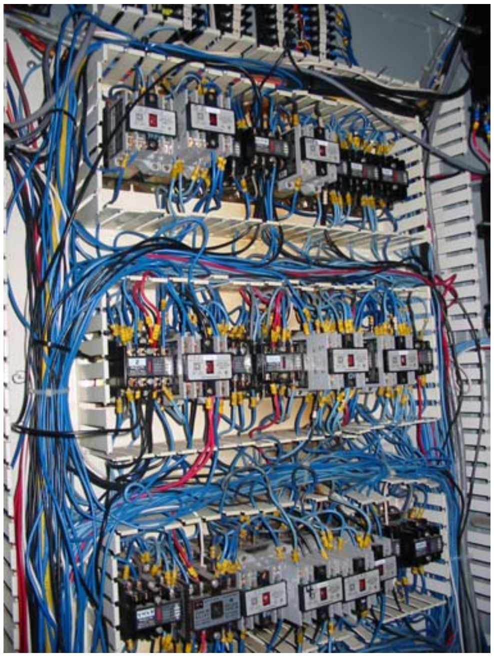
Although the installation is only 20 years old the protective relaying does not include the minimum protection requirements as established by IEEE C37.102-1987. The addition of generator ground fault protection (59GN), rotor field protection (64F) and reverse power protection (32) are required to meet the minimum requirements of the IEEE standard.

Vibration Monitoring

There is no vibration monitoring on the turbine or generator systems. Vibration monitoring should be provided to detect mechanical failures before they can cause permanent damage to the turbine or generator. Trending can be achieved through a PLC to provide insights into the development of problems and allow proactive scheduling of maintenance before failures occur.

Generator Sequencing and Control

The interposing relays associated with the sequencing logic were under designed by the OEM and as a result are the cause of many unit trips. Over the years, numerous relays have been replaced and the number of trips has been reduced. However, relay failures still account for a significant number of unit trips.



Interposing Relays

Over the past five years 26% of all unit trips can been attributed to intermittent loss of the speed reference signal. This is not an unusual situation with electronic controllers employing analog circuitry. When control is provided through a PLC the logic will delay unit trips on loss of speed reference to allow the signal sufficient time to return to normal.

Another common problem with the control system is failure of the voltage regulator's under frequency and over voltage module. In the past these boards have been repaired in house, however integrated circuits and discrete electronic components have become difficult to source. Replacement of the analog voltage regulator with a digital unit will ensure continued support for the system.

Pressure Relief Valve

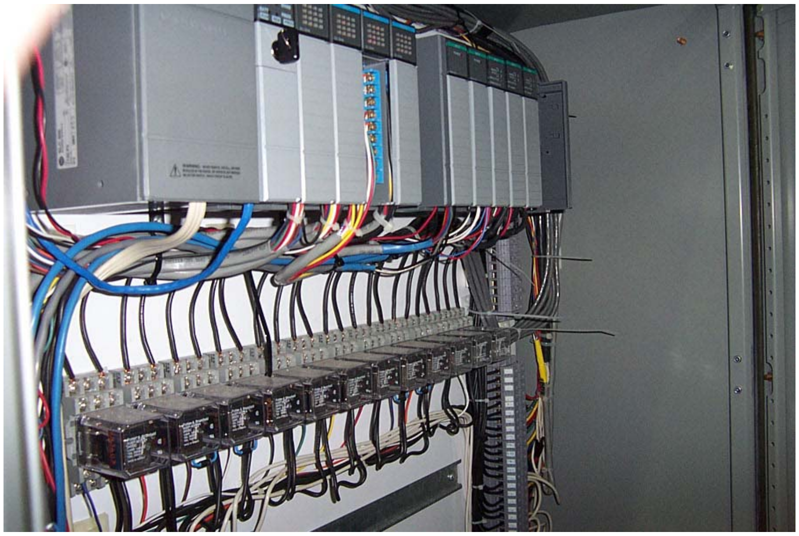
As there is no surge tank associated with the penstock, a pressure relief valve (PRV) is required to relieve pressure under full load rejection. A tracking system was designed to preset the pressure relief valve appropriately in the event of a full load rejection on the unit. The tracking system was the result of infield modifications necessary because of a penstock rupture that occurred during acceptance testing of the 1983 turbine generator system supplied by Barber Hydraulic Turbine.

Interfacing with the PRV tracking system has increased the PLC hardware requirements of both the programming effort and the necessary processing power of the PLC. To ensure the long term reliability of the system it is felt that integrating the control of the PRV into the PLC ladder logic improves control and protection for both the PRV and the penstock.

Pressure Relief Valve

Existing PLC

The existing PLC is an Allen-Bradley SLC model 5/03 acting as a buffer between the electronic governor controller and the hydraulic pressure unit. This modification was completed to increase the reliability of unit synchronization, as the electronic controller was unable to maintain synchronous speed at speed no load conditions. The 5/03 processor has insufficient computing to provide a governing function. In addition, the number of input/output points is limited due to the size of the equipment enclosure.



Allan-Bradley PLC System

The existing equipment cabinets have utilized all available floor space in the plant. The existing PLC cabinet is positioned on a rear wall behind the existing switchgear. Access to the cabinet is limited and there is no room to expand.

Location of existing PLC

To provide the necessary space for a governor PLC, it will be necessary to replace an existing equipment enclosure with an enclosure that also includes the governor function.

Unit Control Panel and Generator Breaker

The replacement of the sequencing logic and associated controls presents an opportunity to combine both the governing function and the protection and control function into a single enclosure.

Recommendations

This report recommends the following:

- The project to replace the governor system with a PLC solution be carried over to 2004.
- A new project to upgrade the protection and control systems at Topsail plant be included in the 2004 Capital Budget.
- The system be designed similar to the unit control panels at Seal Cove and Tors Cove, including the governor function in the unit control PLC.
- The existing Voest-Alpine electronic governor controller be decommissioned and salvaged for spare parts for other in service units at Lawn and Lookout Brook plants.
- The existing protection and control systems be decommissioned.
- Engineering design be completed in 2003 to ensure project completion early in 2004.

Appendix A

Topsail Plant Operators' Log

Energy Supply
Appendix 1
Attachment B

Morris Plant
Turbine & Stationary Seal Inspection

April 12 2000

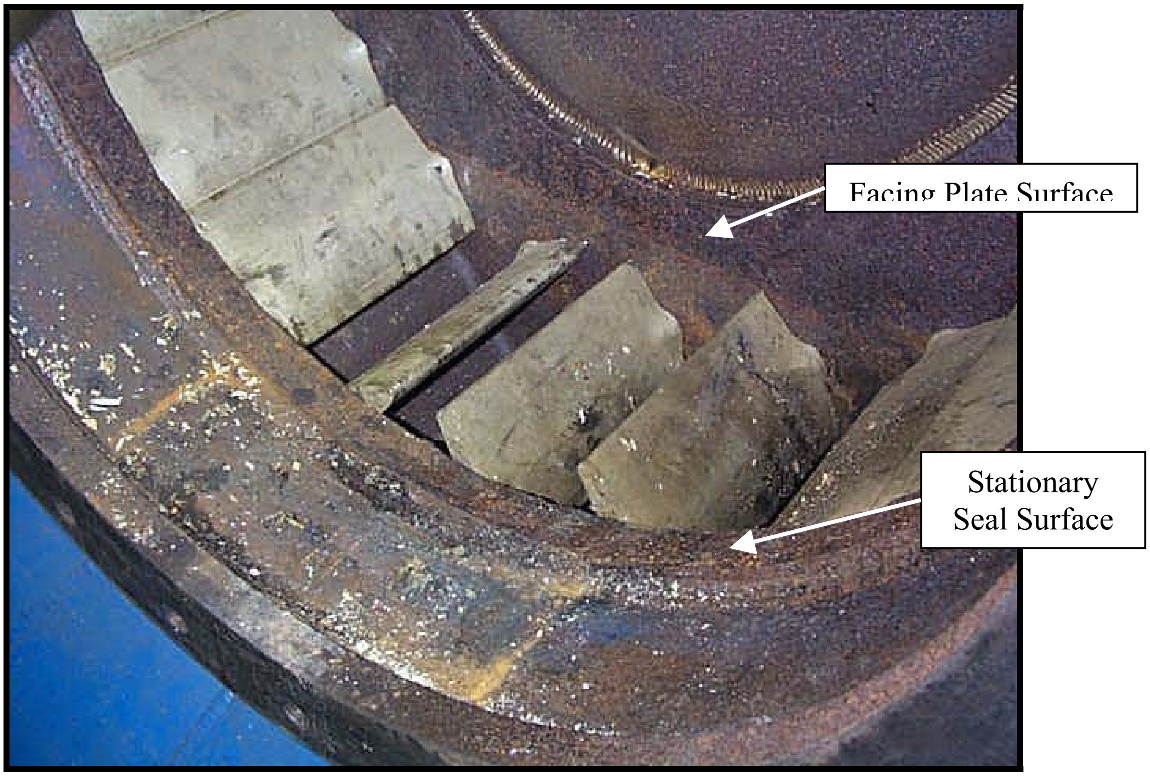
Turbine Inspection

Technical Specifications

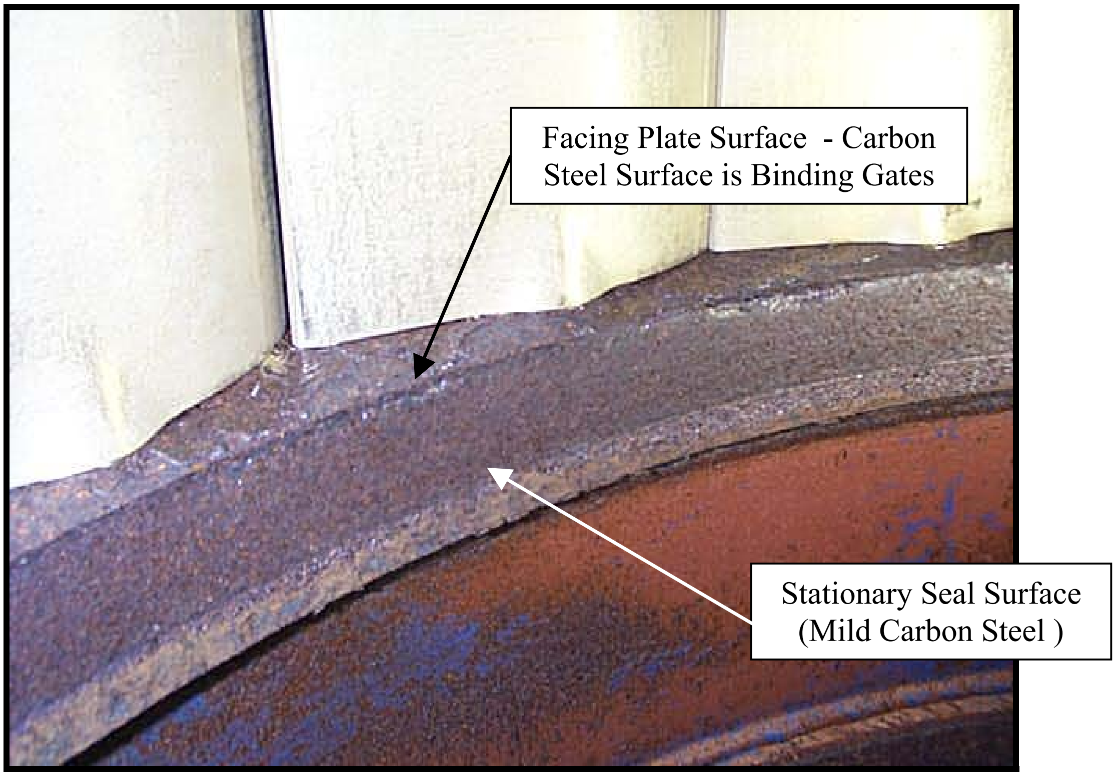
Size:	1100 kW
Manufacturer:	Barber Hydraulic Turbines
Date of manufacture:	1983
Serial Number:	1050
Type:	Francis

Assessment

This unit was installed as a new plant in 1983 by Barber Hydraulic Turbines. The turbine is a horizontal Francis Turbine. In April 2000 operators were experiencing problems with the wicket gate operating ring jamming and acting sluggishly. The turbine was opened up and inspected and it was found that the stationary seals in this turbine were mild carbon steel, and not Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminum-bronze alloy typically found in our other hydro plants. The carbon steel stationary seals had corroded and rust had accumulated to the point that the two ends of the wicket gates were getting jammed in between the two stationary seals. The photo attached below shows the mild carbon steel stationary seals on the Morris Hydro Plant Turbine.



The next photo shows the area where the stainless steel wicket gates were getting jammed due to the rust accumulation on the carbon steel stationary seals.



Recommendations

The carbon steel stationary seals should be replaced with either Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminium-bronze alloy typically found in our other hydro plants.

Project Title: **New Chelsea Hydro Plant Refurbishment**

Location: **New Chelsea, Trinity Bay**

Classification: **Energy Supply**

Project Cost: **$3,973,000**

See Attachment A, *"New Chelsea Plant Planned Refurbishment – 2004"*, outlining the rationale and justification for this project.

Energy Supply
Appendix 2
Attachment A

NEW CHELSEA PLANT
PLANNED REFURBISHMENT 2004

NEWFOUNDLAND POWER
Engineering & Energy Supply Department

NEWFOUNDLAND POWER

Engineering & Energy Supply Department

NEW CHELSEA PLANT
PLANNED REFURBISHMENT 2004

Table of Contents

Page

Introduction

On September 24, 1954 the Public Utilities Board required that Newfoundland Power's predecessor United Towns Electric provide electrical service to the communities of Hant's Harbour and Old Perlican. As a result, construction began on the New Chelsea Hydroelectric Development. The generating station, with an installed capacity of 3.7 MW, went into service in January 1957 at a construction cost of just over $2.5 million. Two years later the development was expanded when a 0.6 MW generating station was constructed at Pitman's Pond upstream from New Chelsea. The design of the Pitman's Pond generating station allowed for remote control from New Chelsea. In 1960, the generating station at Hearts Content was redeveloped, and was also remotely controlled from New Chelsea. Since that time there has been very little in the way of major refurbishment work at New Chelsea, except in 1986, when the three generating stations were automated to provide remote control from the System Control Centre in St. John's. The control panels, switchgear and protection systems at New Chelsea all date back to the original 1956 installation.

In 2004 the major systems in service at New Chelsea will be 48 years old. The expected life of this type of equipment as established by the Institute of Electrical and Electronic Engineers (IEEE) ranges from 25 to 40 years. The existing woodstave and steel penstock has also deteriorated to the extent that replacement is necessary to ensure continued safe and reliable operation. This presents an opportune time to complete refurbishment of other systems at this facility, since replacement of the penstock will result in a five-month period when the plant will be unavailable for operation. Refurbishment of the other plant systems can be completed in this time period, hence avoiding the need for another prolonged plant outage and associated water spillage in future years.

The justification for the project is based on a combination of dealing with obsolescence, maintaining public safety, supporting environmental stewardship and ensuring reliable electricity supply from this facility.

Role in Power System

New Chelsea provides approximately 15.4 GWh of energy on an annual basis, or 4% of total hydroelectric production for Newfoundland Power. In addition, it provides 3.7 MW of power to the Hants Harbour, New Chelsea and Old Perlican areas in the event of a loss of in-feed through transmission line 43L from Hearts Content. The generator also plays a role in maintaining acceptable voltage levels on this long radial transmission system.

Scope of Work

The scope of this project includes modifications to the electrical, mechanical and civil works of the plant and the 66 kV substation. The site assessments included in the appendices of this document form the basis of the Scope of Work and the associated budget estimate. The following is a summary of the scope of work:

Electrical Work

AC Station Service

The existing 69,000-volt to 600-volt delta station transformers will be replaced. This secondary voltage is non-standard voltage and there are no spares available for the three single-phase transformers. The potential failure of one or more of these transformers places the operation of the plant at risk. They will be replaced with a 6,900-volt to 120/208 volt, wye, three-phase dry-type transformer located inside the plant in a new switchgear cabinet. In addition, a backup station service will be provided from the substation yard using three standard pole mounted transformers and connected to the switchgear with a manual transfer switch. This will provide a contingency in the event of the failure of the dry-type transformer.

Station Service Transformers

The existing 600-volt delta, 3 phase AC service is non-standard and antiquated with numerous auxiliary panels associated with the distribution system. The system will be modernized and consolidated into a single 120/208 volt three phase panel to provide a standard station service supply.

DC Distribution and Battery Charger

The DC distribution panel and battery charger will be replaced. The DC distribution is original to the 1956 installation and the battery charger was installed in 1975. Replacement breakers are not available for the DC distribution panel and spare parts are no longer available for the battery charger. The battery bank was replaced in 1996 and is in good condition.

Switchgear and Power Cables

The existing breaker used to connect and disconnect the generator is located on the high side of the unit transformer resulting in inadequate protection of the generator. The refurbishment will include a new generator breaker installed in conjunction with a digital multifunction protection relay to provide the required generator electrical protection. The switchgear will include new current and potential transformers to replace the units supplied in the 1956 installation. The switchgear will also include a new field breaker, generator neutral grounding reactor, station service transformer and a grounding system for isolating the generator bus for maintenance. The existing breaker and disconnect switch will eventually be replaced with power fuses and an airbreak switch.

The existing power cables went into service in March 2000 and remain in good condition. These power cables will be re-terminated in the new switchgear. Modifications to the bus connection between the generator output terminals and the power cables will be required to interface with a new generator breaker.

Generator

The generator windings are original and have never been rewound. After 48 years in service they have significantly exceeded the average life expectancy of 30 years, which places the reliability of the plant at significant risk, with the potential of six to eight months of downtime and associated spillage of water.

The unit will be rewound as part of this project. The excitation system is in good condition, requiring only a general cleaning and replacement of those parts demonstrating excessive wear. The slip rings and commutator will be inspected prior to shutdown, machined and undercut if required.

Generator Protection and Control

The unit sequencing and control will be implemented using a Programmable Logic Controller (PLC), replacing the numerous discrete relays currently in service. The PLC will be part of our standard Unit Control Panel (UCP) design supplied locally. The UCP will also include a synchronizer, voltage regulator and production metering.

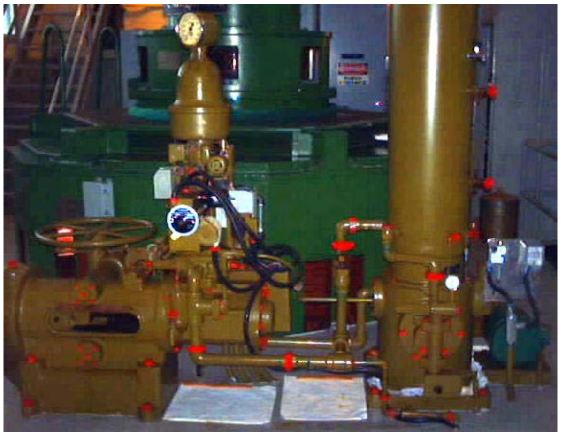
The existing generator protection provided through electromechanical relays does not meet the IEEE recommended minimum set of protection for a generator of this size and duty cycle. To meet the standard the following protection will be added using a multifunction digital generator protection relay:

- Loss of excitation
- Over-voltage protection
- Over-frequency protection
- Stator thermal protection

Governor

Recent experience indicates that the existing governor speed droop is inaccurate and it is no longer able to properly regulate frequency when operating isolated from the provincial power grid. Frequent adjustments are required and, as a result, there are concerns with the quality of power provided to customers when supplying local load. The Woodward governor is original to the plant and is difficult to maintain. The manufacturer is no longer able to provide replacement parts and has limited their support to system upgrades and retrofits. As a result, replacement parts are machined locally and do not meet the tolerances of the original specifications. In addition, the pressurized oil system employed by this governor exposes the plant to the risk of oil release into the tailrace.

There are two options for replacing the original governor. The mechanical governing head can be replaced with an electronic upgrade from the original manufacturer. The hydraulic system would undergo replacement of some parts no longer available and refurbishment of the power piston. The second option is to replace the Woodward system entirely with an all-electric solution, thereby reducing the use of oil at the facility. One significant technical issue to overcome is related to the fact that the existing Woodward governor is mechanically linked to a pressure relief valve. Both solutions have a similar cost, and the final decision as to which option should be implemented will be determined during the detailed engineering design stage. An additional benefit resulting from the implementation of either of these solutions is the provision of spare parts that will be used to maintain similar units still in service.



Woodward Governor

Instrumentation

The unit does not have stator temperature, vibration or bearing oil level monitoring and protection while the bearing temperature protection is of 1956 vintage and requires upgrading. This protection is recommended for a plant of this size. The instrumentation and protection systems on the generator and turbine will be upgraded to include the following:

- Bearing thermocouples or RTD’s (two per bearing)
- Vibration monitoring (one per bearing)
- Oil level switches (one per bearing oil pot)
- Stator RTD’s (6 10-ohm copper elements)
- Incorporate speed switch into UCP

Bearing Cooling Water Control

Automating the valves and flow meter in the bearing cooling water system through the UCP will enhance mechanical protection for the turbine and generator. Cooling will be provided only when required to maintain constant bearing temperature.

Heating and Ventilation

The existing manual louver system will be motorized and automated to provide improved temperature regulation. Heating of the plant and generator will be controlled through the UCP. These enhancements will provide heat to the stator when the unit is shut down and cooling air to the plant by opening the building louver and operating the exhaust fan when the building ambient temperature increases. The ability to close the louvers when the unit is not operating will reduce energy loss from the plant. Maintaining a controlled environment within the plant will ensure that problems related to condensation will not lead to electrical failures of the generator and associated equipment.

Forebay Water Level Monitoring and Control

The existing water level probe and transducer are obsolete, cannot be accurately calibrated and are no longer supported by the manufacturer. The new system (PLC and water level probe) will be interfaced with the UCP as required to provide efficient water management.

A detailed assessment of the protection and control is provided in Appendix A.

Mechanical Upgrading

Turbine

The scroll case vent and 4-way control valve will be replaced with an automatic float type vent, eliminating the need for separate control valves and electrical interface.

The wicket gates will be replaced or refurbished to reduce the potential of sticking and causing undue wear and tear on governor arms and linkages. It will also reduce the run down time on shutdown.

The turbine shaft gland seal and shaft sleeve will be inspected and replaced or refurbished as required to prevent water leakage.

Bearing Cooling

All bearings will be refurbished as required during the turbine upgrade.

The cooling water system is now fed from two 1 ½” Y type strainers. These will be replaced with a more conventional duplex filter element system.

The cooling water system will be replaced or refurbished as required.

Heating and Ventilation

The stationary intake louvers and shutters will be replaced with a motorized louver system. The control for the plant heating and ventilation will be upgraded by incorporating it into the PLC logic control. Concrete repairs to the louver opening & sill plates will also be completed.

A detailed assessment of the turbine is found in Appendix B.

Civil Work

Powerhouse

Concrete rehabilitation is required in the tailrace area in the vicinity of the water line. The damage is caused by salt-water spray and the freeze thaw cycles experienced in the ocean environment.

Penstock

The project involves the replacement of the 867 metres of 1,829 mm diameter woodstave penstock and 240 meters of steel pipeline. The new penstock is to be constructed with steel and dimensioned similar to the existing woodstave penstock. Drainage will be improved near the steel pipeline by installing culverts and porous gravel where required to reduce the risk of corrosion of the pipe.

A detailed assessment of the condition of the penstock is included in Appendix C, and the internal inspection completed by FGA-CANSPEC consulting engineers in Appendix D.

Substation Work

Transmission Line Protection

At present the transmission line protection is spread across the various generator control panels in the plant control room. This is the result of piecemeal protection and control upgrades throughout the life of the plant. The existing generator protection and control panels will be decommissioned to make room for the new Unit Control Panel (UCP). As a result new transmission line protection panels will be required, which will consolidate the various protection elements and greatly simplify the operation, maintenance, testing and troubleshooting of the system.

Substation Modifications

The existing transformer breaker (NCH-T2-B) is used to synchronize the generator to the power grid. With the addition of a generator breaker this function will no longer be required. The condition of the breaker is questionable and it will eventually be decommissioned. To accommodate the synchronization of the new generator breaker a potential transformer will be installed on the 66 KV bus.

Station service for the substation is provided from the plant station service. This design does not address the situation where station service in the plant is shut down for maintenance. A dedicated substation station service is required to ensure a reliable supply of AC power to the equipment in the substation.

The existing transformer T2 protection provided through electromechanical relays consists of a transformer differential (87T), time delayed overcurrent (51N), and instantaneous overcurrent (50). These protection functions, along with others deemed necessary through a general protection review, will be included in a digital transformer and bus protection relay.

Justification

The project is justified on obsolescence, public safety, environmental stewardship, customer and plant reliability and financial considerations. Examples of each type of justification are provided in this section.

Public Safety

The existing woodstave penstock has progressively deteriorated over the 48-year life of the facility. Considerable effort has been made in recent years to contain leaks from the pipeline, and in the past year two major blowouts have had to be repaired.

Environmental Stewardship

The replacement penstock will be steel and permit the removal of the existing creosote-treated woodstave penstock from the environment.

The amount of oil at the facility would be dramatically reduced by the replacement of the hydraulic governor with an all-electric solution, should this alternative be selected.

The addition of a water management algorithm in the Unit Control PLC (UCP) will support the efficient use of water resources and reduce the risk of spill.

Maintaining hydro production at this plant will reduce the need for burning fossil fuel at Newfoundland Hydro’s Holyrood Generating Station.

Reliability

Replacing the manufacturer-discontinued and obsolete equipment at the plant with commercially available equipment will reduce the number of equipment failures, and reduce the duration of unscheduled downtime. This will improve customer reliability when the plant is required to supply local generation and plant reliability by increasing availability and maximizing output.

Financial

The cost of energy for this plant, including the capital expenses associated with this and other planned projects, at 3.19 cents per kilowatt hour is substantially less than the cost of energy for new developments such as Rose Blanche, or thermal sources such as Holyrood. A detailed financial analysis is provided in Appendix E.

Recommendation

Old, deteriorated, high-maintenance equipment places the reliability of the plant at risk and raises concerns regarding potential penstock failure and associated environmental impacts. Newfoundland Power should proceed with this project in 2004. The project will benefit the Company and its customers through improvements in safety, environmental stewardship and reliability. It will reduce the operating and maintenance costs of the plant. Investing in the life extension of facilities such as New Chelsea guarantees the availability of low cost energy to the Province. Otherwise the annual production of 15.4 GWhs would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station.

Appendix A

Protection and Control Site Assessment

NEW CHELSEA REFURBISHMENT PROJECT

SITE ASSESSMENT

Protection and Control

General

The New Chelsea hydro development went into service in January 1957 with a construction cost just over $2.5 million. Since that time there has been very little in the way of major refurbishment work. The plant was automated in 1986, at which time remote control was provided. The control panels, switchgear and protection systems date back to the original 1956 installation.

AC Distribution

The existing 600 volt 3 phase AC service is antiquated and there are numerous auxiliary panels associated with the distribution system. The system needs to be modernized and consolidated into a 600 volt three phase panel and a 120/240 single-phase panel. Another option would be to provide a 120/208 three-phase panel if the existing 600 volt equipment is to be replaced.

Station Service

The existing 69,000-volt to 600-volt station service transformers are unique and we carry no spare units in our system. These units are larger than necessary and can easily be replaced with either standard distribution transformers or a three-phase dry type transformer located in a new switchgear line-up. This will allow for easy replacement if a single transformer were to fail in service. Also there is no emergency station service. Consideration should be given for an emergency station service and a manual transfer switch.

DC Distribution

The DC distribution panel needs to be replaced. The panel was installed in 1956 and replacement breakers are no longer available.

Battery Plant and Charger

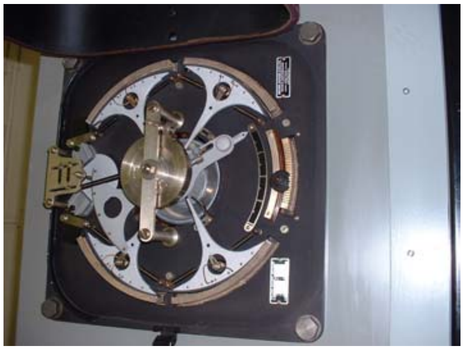
The batteries are in good condition. Records show that the battery bank was replaced in 1996. The charger was installed in 1975 and should be replaced due to unavailability of spare parts.

Generator

The generator windings are original and have never been rewound. At 48 years in service, this generator exceeds the average life expectancy of 30 years. Therefore, a rewind of this unit is warranted.

Excitation System

The excitation system is in good condition, with the exception of the antiquated voltage regulator. The unit control panel will be supplied with a digital voltage regulator to interface with the exciter. Consideration should be given for a brushless exciter if savings in maintenance costs can be demonstrated.



Switchgear

There is no generator breaker with this generator. As a result there is inadequate protection on the generator. The refurbishment will require a new generator breaker be installed to work in conjunction with the digital protection relay to provide adequate generator electrical protection. As a result the protection and control system for the step up transformer will need to be redesigned.

Power Cables

The power cables were replaced in March 2000. The power cables will remain in service and be connected to a new generator breaker. The bus connection between the generator output terminals and the power cables will need to be modified to accept a new generator breaker. The existing PTs and CTs will be replaced with the new switchgear.

Grounding

The generator has a high impedance ground for protection provided in the CT compartment. This compartment will be removed and replaced with a switchgear cabinet. Therefore the original 1956 grounding transformer will either have to be replaced or relocated if it is found to be in good condition.

Protective Relays

The existing generator protection provided through electromechanical relays consists of:

- Generator differential
- Rotor ground fault
- Stator unbalanced current
- Ground fault
- Generator ground fault
- Split phase differential protection

- Voltage restrained overcurrent

The recommended minimum set of protection was provided on this generator, with the exception of the following:

- Loss of excitation
- Over-voltage protection
- Over-frequency protection
- Stator thermal protection

The existing transformer protection provided through electromechanical relays consists of:

- Transformer differential
- Time delayed overcurrent
- Instantaneous overcurrent

Alarm Annunciation

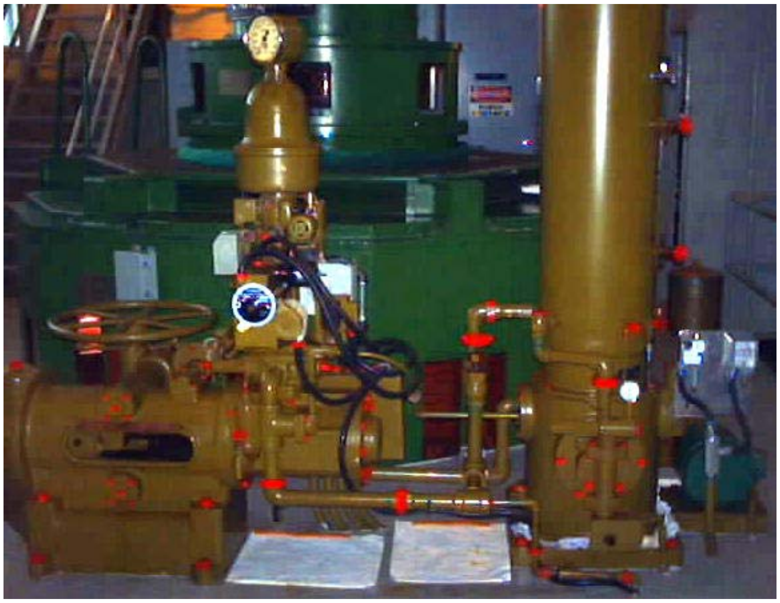
There is little or no annunciation of local plant alarms through the existing control panels.

Governor

Reports from the local staff indicate that the governor performs acceptably when the generator is parallel with the power system. However, when operating isolated from the grid and supplying local load the governor does a poor job maintaining frequency. The quality of power provided by the generator when supplying isolated local load is below acceptable power quality standards.

The existing Woodward governor is mechanically linked to a pressure relief valve. This will impact design solutions for a governor replacement.

Options for governor replacement include a Woodward 505H upgrade (including power piston overhaul) or a new hydraulic replacement, along with the all electric solutions employed recently at Newfoundland Power.



Instrumentation

The following protection additions or enhancements to the existing system protection need to be addressed during a system refurbishment:

- Bearing thermocouples or RTDs
- Vibration Monitoring
- Oil level switches in the bearing pots
- Incorporate the six 10-ohm copper RTDs into the unit control PLc
- Incorporate speed switch

Bearing Cooling Water Control

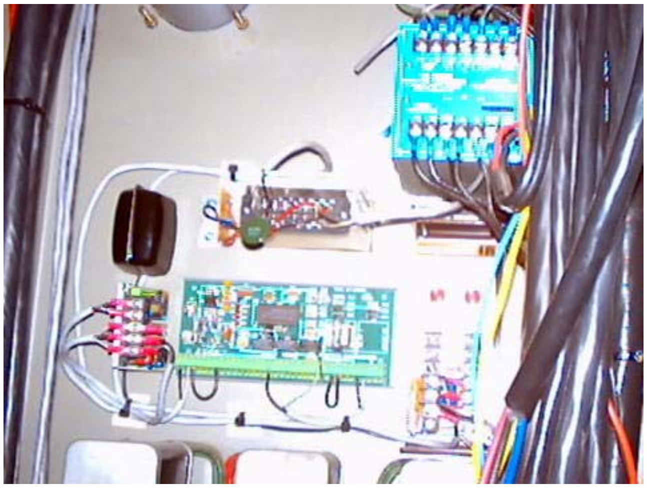
The existing bearings require water-cooling to ensure safe operating temperatures are maintained. There are valves and piping in place, however there is no automated control of these valves at present. Automating the bearing cooling system will ensure that problems are detected before damage is done to the bearings or shaft, thereby eliminating costly future repairs.

Heating and Ventilation

The existing louvers are not controlled. Unit heating and cooling should be incorporated into the unit control PLC.

Forebay Water Level Monitoring and Control

The existing water level probe and transducer are the older vintage Intertechnology equipment. The equipment is manufacturer discontinued and spare parts are no longer available. This equipment should be replaced with a new 4 to 20-milliamp water level transmitter and interfaced with the unit control PLC.



Associated Work

The T2 transformer and transmission line protection for 44L, 43L and 65L is provided by electromechanical relays. The control switches, relays and metering are spread out across the existing plant control panels. To provide sufficient space to install the new protection and control panels, these existing panels will have to be removed. Therefore, the existing transformer and transmission line protection will have to be addressed as part of this project. It is recommended that the substation design group consider replacement panels using the digital protective relays.

Also the existing control panels provide control switches for operating T1-A and T3-A from the plant control room. Control of these switches will have to be included with the T2 transformer protection panel.

Appendix B

Turbine Inspection

New Chelsea Plant
Turbine Inspection

Turbine Inspection

Technical Specifications

Size:	5600 Hp
Manufacturer:	Dominion Engineering Turbine
Date of manufacture:	1956
Serial Number:	816
Type:	Francis

Assessment

The unit was overhauled in 1985 replacing the runner, wicket gates, bushings, and both stationary seals. These components are in good condition with very little wear or evidence of impact damage to the exposed surfaces.

The runner is stainless steel welded construction. The elevation of the runner in the water passage is approximately 3/16" low however this has not caused any erosion to the runner components. See photo 2 - upper seal and runner.

Photo 1 – Wicket Gates

Photo 2 – Upper Seal &Runner

There are small cracks near the root of the weld on several of the runner blades to the inner band. These are most likely surface cracks and do not pose any immediate threat to the integrity of the runner. These will be checked during the next inspection.

The wicket gates are in good condition with very little wear on the sealing surfaces. The heel to toe clearance on the gates is excessive approximately 1/8" in the closed position. This maybe corrected on the eccentrics. If not the gates will have to be repositioned and the gate arms re-doweled. See photo 1 - wicket gates and stay vanes.

Photo3 – Wicket Gate

The scroll case is in relatively good condition with no signs of major pitting or erosion of the base metal. No cracks in the casing sectional welds that were accessible for viewing. The stay vanes are in good condition with no signs of impact damage or major wear. See photo 3 and 5 - scroll case, wicket gate and stay vane.

Photo 4 – Main Valve

Photo 5 – Scroll Case

A full inspection of the main valve could not be completed due to leakage in the head gate that prohibited the opening of the valve. There is some erosion on the downstream side of the disc, a section approximately 3" in diameter and ¼" deep has delaminated from the base metal. See photo 4 of the Main Valve. The drive sleeve on the valve actuator was weld repaired this year, as replacement parts were unavailable from the manufacturer due to the vintage of the unit.

The pressure relief valve is original equipment and was overhauled in 1990 by Colonial Garage. The actuator cylinder was honed and a new ring installed on the piston to prevent governor oil from bypassing the piston, and migrating into the dashpot cavity causing the dashpot to overflow. The problem persisted and in 1994 a shutoff solenoid was installed in the oil line from the governor oil system to shutoff the supply oil when the valve fully closed.

The governor and control linkages were inspected for worn bushings and lost motion. The cross head on the dump valve connecting arm needs to be re-bushed to reduce the excessive play in the cross head. See photo 6 -Gate operating Arms and Dump valve.

Photo 6 – Gate Operator Arms

Photo 7 - Governor

There is a small amount of play in the governor-operating arm. The needle valve in the dashpot on the governor control head is worn and cannot be properly adjusted. See photo 7 - Governor. The manual gate limit adjustment is seized, and this is left at maximum or 100%.

The pumping unit is in relatively good condition, with no major oil leaks. The unit maintains proper operating pressure and accumulator air volume. The unit was recently fitted with new pressure switches and oil pump motor.

The air intake louver and exhaust fan are in a poor state of disrepair and will need to be replaced within the next couple of years. See photos below:

Photo 8 – Exhaust Fan

Photo 9 – Intake Louver

Recommendations

The scroll case vent and 4-way control valve needs to be replaced with an automatic float type vent, eliminating the need for separate control valves and electrics.

The wicket gates need to be closed up and re-doweled to reduce run down time on shutdown.

The stationary intake louvers and shutters need to be replaced with a motorized louver system. The control for the plant heating and ventilation should be incorporated into the PLC logic control for the plant. There are some concrete repairs required to the louver opening & sill plates.

The pressure release valve cross head needs to be re-bushed. The remaining linkages and bushings should be inspected when the unit is taken out of service next year.

The pressure release valve should be removed and a full internal inspection and any necessary repairs completed when the unit is taken out of service.

All the bearings should be removed and inspected during the overhaul.

The cooling water system is now fed from two 1 ½" Y type strainers, these should be changed to a more conventional duplex filter element system to permit replacement or cleaning of one filter without removing the unit from service.

All cooling water piping and cooling coils to be inspected tested and replaced if required during the overhaul. The upper and lower guide bearing cooling coils were replaced in 1998. The turbine bearing is water-jacketed and should be flushed and tested during the overhaul.

The slip rings and commutator should be inspected prior to shutdown machined and undercut if required.

The turbine shaft gland seal and shaft sleeve should be inspected during the overhaul.

Appendix C

Civil Works Site Assessment

NEW CHELSEA REFURBISHMENT PROJECT

SITE ASSESSMENT

Civil Works

Powerhouse

The powerhouse is in good condition. The exterior of the building and roof appear to be satisfactory. Some concrete repairs are required in the tailrace area at the water line. This area is susceptible to salt water spray and numerous freeze thaw cycles.

View of Back of Powerhouse

Piers in Tailrace Requiring Repairs

Dams

The dams are in fairly good shape. The forebay dam requires additional riprap in some areas and the spillway retaining wall at the end of the dam requires some concrete replacement.

Penstock

The New Chelsea penstock is comprised of 867 m of 1829 mm diameter woodstave and 240 m of 1524 mm diameter welded steel, with the lower 180 m being buried below ground.

The New Chelsea penstock has been in service for about 48 years. Based on previous penstock replacements the life of a woodstave penstock is in range the 45 - 50 years. The woodstave section of the New Chelsea penstock is in a similar condition of deterioration as the other woodstave penstocks that have been replaced by Newfoundland Power in the last five years. The life of a buried steel penstock should be greater than 50 years, however, recent inspections of the steel penstock have shown that this is not the case with the New Chelsea pipe. Both the woodstave and steel sections of the penstock are in poor condition and need to be replaced.


Woodstave Section


Section of Steel Penstock Half Buried

A recent inspection of the woodstave penstock indicates that the woodstaves continue to deteriorate. The majority of the woodstaves along the spring line are crushed and some are starting to bulge and feather around the steel rings. Numerous holes have been plugged in the penstock with wooden wedges (approximately 20,000) over the last few years and in the last year two major blowouts had to be repaired. Overall, the frequency of repairs has increased in recent years. There are three or four areas where large sections of woodstave have blown out and were repaired by bridging the missing woodstave with steel plate and gasket material.


Steel Plate Bridging Missing Woodstave


Crushed Woodstaves

Due to the excessive amount of leakage the bedding material below the penstock is saturated and drainage is poor. In some areas the timber cradles have settled into the bedding material and notable sags can be seen in the penstock alignment. In some areas the penstock is in contact with the ground. Several cradles are cracked and showing signs of failure. The operator reports that in recent years over 100 plates have been installed to repair cracked cradles.


Failed Cradle


Penstock in Contact with Ground

The exterior section of steel penstock that is above ground is in good condition for the age of the pipe. As the penstock enters the ground it was noted that the soil around the pipe has poor drainage with standing water around the pipe.

To assess the condition of the steel penstock an internal and external inspection of the buried pipe was conducted in June 2003 (for inspection results see Memorandum from Gary Murray to Gary Humby dated June 16, 2003). The internal inspection was conducted by FGA-CANSPEC and consisted of visual and ultrasonic testing to determine the wall thickness of the steel penstock. The inspection showed that the inside of the pipe was severely corroded and that the wall thickness is below the design requirement. The external inspection revealed that the pipe is also corroded on the outside, but to a much lesser extent than the inside of the pipe. The external inspection also showed that the backfill material is not free draining and in places the penstock is sitting in saturated backfill. The backfill material is not considered suitable for this type of installation.

In conclusion, the woodstave penstock has passed its reliable service life and needs to be replaced. It would have been expected that the steel penstock would be good for another 20-25 years, however, investigations reveal that the steel section has also deteriorated to a condition, where it must be replaced before reliability or failure become an issue. Based on the above the entire penstock should be replaced in the next year.

Appendix D

Steel Penstock Assessment

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 16, 2003

Memorandum From: **Gary L. Murray**

To: **Gary Humby**

Subject: **New Chelsea Rehabilitation Projects – Inspection of Steel Penstock**

File: **401.01.03.23.00**

As part of the study on the replacement of the New Chelsea Penstock we carried out an inspection of the existing steel penstock section. The purpose of the inspection was to determine the condition of the pipe and the amount of the steel wall (thickness) remaining.

The section of steel penstock at New Chelsea is approximately 240 m in length with about 60 m above ground and 180 m buried below ground. According to the original design drawings the wall thickness is 10 mm, except for the lower elbow at the powerhouse, which is 12mm.

On June 3, 2003 FGA-CANSPEC did an internal visual inspection of the penstock and ultrasonic testing to determine the wall thickness. A copy of their report is attached. In summary they inspected 60 m (200 ft) of pipe (30 m upstream of the access manhole and 30 m downstream of the manhole).

The inspection revealed that there is a 25 – 50 mm sludge adhered to the internal surface of the pipe. The sludge was removed at the locations where inspections were performed. Removal of the sludge revealed heavy pitting of the penstock wall in the range of 3 - 5 mm. Ultrasonic test measurements showed that the wall thickness ranged from 3 to 10 mm with the majority of the readings being well below the original design of 10 mm. The average thickness reading in the section below the manhole was 5.74 mm, and 4.43 mm above the manhole. The average reading of all measurements was 5.09 mm. Since the measurements were taken in the pitted areas the numbers have to be interpreted properly. The numbers should not be interpreted as saying that only half of the wall thickness is remaining. However, it would be fair to conclude that the penstock is severely corroded and that the integrity of the penstock is questionable.

The sludge growth and pitting was most evident on the internal surface of the pipe from the 2 –10 o'clock position (top of pipe being 12 o'clock). This would seem to indicate a link between the sludge and amount of corrosion. Based on current design requirements the design thickness of the penstock should be around 8 mm with a 2 mm allowance for corrosion. Based on these requirements it could be said that the penstock has deteriorated beyond its service life.

Based on the findings from the internal inspection we decided to perform an external inspection of the penstock by excavating test pits next to the penstock to observe the external condition of the pipe. This inspection was carried out on June 12, 2003. Three test pits were excavated along the penstock: 1) at the manhole; 2) 25 m downstream of the manhole; and 3) adjacent to the substation (about 40 m from the powerhouse).

At the first location the top of the pipe was at grade and the water table was 300 mm below grade. The fill around the penstock was a till material with a high clay content and some gravel and cobbles. The top half of the pipe showed signs of external corrosion with severe pitting. The bottom half of the pipe was in much better condition with some corrosion. Rusty water could be seen flowing below the penstock and quickly started to fill the excavation.

At the second location the top of the penstock was about 1.5 m below grade. The backfill material was similar with a little less clay content and more gravel. Similarly the top half of the pipe was corroded with less corrosion on the lower half. The water table was about 300 mm above the bottom of the pipe and water flowed freely from along the bottom of the pipe into the excavation.

At the third test pit the top of the pipe was at ground level. Corrosion was evident at the top half of the pipe, however the depth of the pitting was negligible. The backfill material around the pipe could be classified as a dirty gravel with a till material below the pipe. The water table was at the bottom of the pipe. As with the other locations, but to a lesser extent water was flowing along the bottom of the pipe.

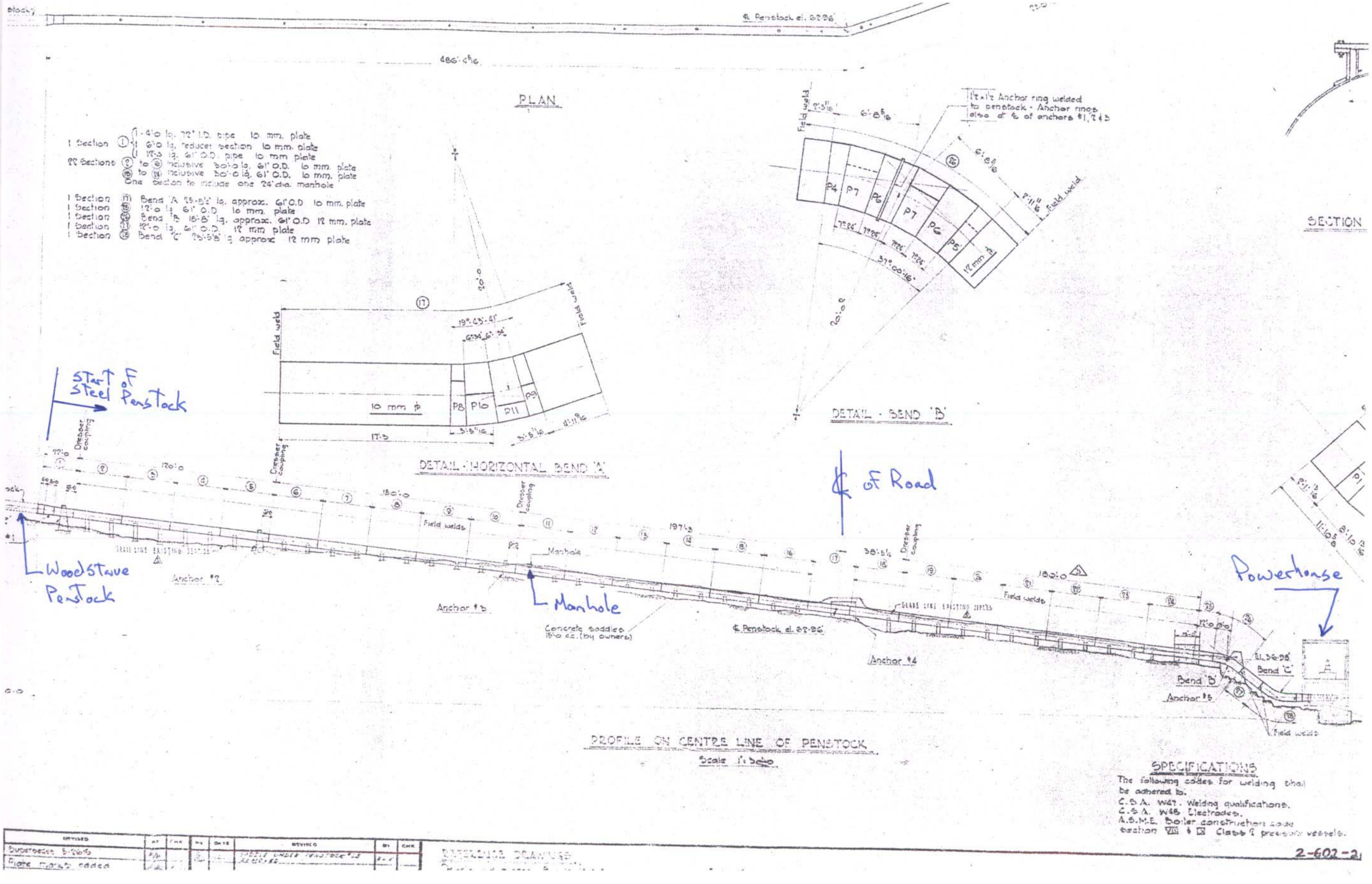
In conclusion, the internal and external inspection of the penstock revealed that the penstock is severely corroded and the thickness is below the design requirement. The deterioration of the pipe seems to be more from the internal corrosion rather than the external corrosion.

The penstock may very well be pitted completely through and leaking in some areas. With pressure rises in the pipe from normal and emergency shutdowns at the plant, penstock leakage and resulting erosion of the bedding material could become problems into the future. While a failure of the pipe is not a concern at this particular time the penstock has passed its reliable service life and should be replaced in the near future.

Based on the extent of internal bacterial growth and corrosion seen in the existing pipe consideration should be given to an internal coating on the new penstock pipe.

Regards,

Gary L. Murray, P. Eng.
Project Engineer



1 Section ① { 1 - 4'-0 lg. 72" I.D. pipe 10 mm. plate
1 6'-0 lg. reducer section 10 mm. plate
1 17'-3 lg. 61" O.D. pipe 10 mm plate }
22 Sections ② to ⑯ inclusive 30'-0 lg. 61" O.D. 10 mm. plate
⑱ to ㉔ inclusive 30'-0 lg. 61" O.D. 10 mm. plate
One section to include one 24" dia. manhole

1 Section ⑰ Bend 'A' 25'-5 1/2" lg. approx. 61" O.D 10 mm. plate
1 Section ㉕ 12'-0 lg. 61" O.D 10 mm. plate
1 Section ㉖ Bend 'B' 16'-8" lg. approx. 61" O.D 12 mm. plate
1 Section ㉗ 12'-0 lg. 61" O.D. 12 mm plate
1 Section ㉘ Bend 'C' 23'-5 5/8" lg. approx 12 mm plate

PROFILE ON CENTRE LINE OF PENSTOCK

Scale 1" = 30'-0

SPECIFICATIONS

The following codes for welding shall be adhered to.
C.S.A. W47. Welding qualifications.
C.S.A. W48 Electrodes.
A.S.M.E. Boiler construction code section VIII & IX Class 2 pressure vessels.

REVISED	BY	CHK	No	DATE	REVISED	BY	CHK
Supersedes 5-2615					SADDLE UNDER PENSTOCK #13 REMOVED		
Plate marks added							

2-602-2

fga-CANSPEC
MATERIALS ENGINEERING AND TESTING

NEW CHELSEA PENSTOCK CORROSION INVESTIGATION

Prepared For:

Mr. Gary Murray
Newfoundland Power
St. John's, NL

fga-CANSPEC Project No. 330 24

June 11th, 2003

fga-CANSPEC

PAGE: 1 OF 3 JOB NO.: 330-24

June 3, 2003

NF Power
New Chelsea, NL
Internal/External Penstock Inspection

Approximately 200' of penstock at the New Chelsea NF Power site was inspected using ultrasonic and visual techniques. This yielded the following results:

Ultrasonic Thickness Readings in Millimeters

Location	1)	7.6	26)	6.9
	2)	10.7	27)	4.6
	3)	4.6	28)	4.0
	4)	4.5	29)	5.2
	5)	4.0	30)	3.8
	6)	6.8	31)	2.6
	7)	6.1	32)	5.6
	8)	8.7	33)	3.5
	9)	4.0	34)	4.7
	10)	6.8	35)	3.3
	11)	5.9	36)	3.3
	12)	4.8	37)	3.7
	13)	5.9	38)	2.7
	14)	5.0	39)	5.9
	15)	5.9	40)	3.5
	16)	4.1	41)	5.5
	17)	6.0	42)	7.6
	18)	6.0	43)	4.5
	19)	8.2	44)	3.1
	20)	5.8	45)	3.4
	21)	4.7	46)	6.4
	22)	6.1	47)	2.5
	23)	3.7	48)	5.5
	24)	3.0	49)	4.8
	25)	4.6	50)	4.2

General Site Findings:

Internal

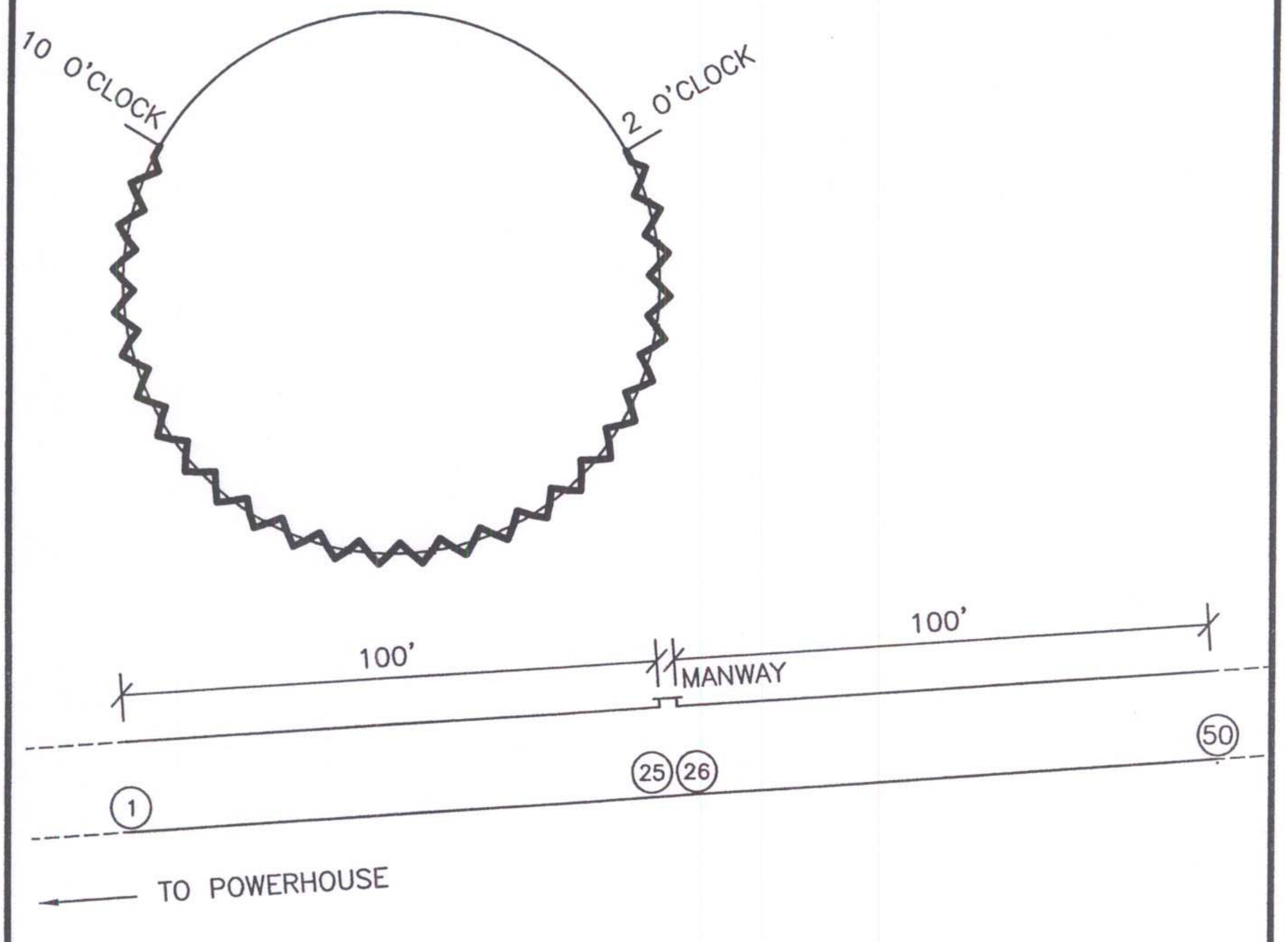
Severe corrosion/pitting was found internally. A 1.5' to 2" layer of sludge had to be removed to facilitate inspection at the fifty (50) UT points listed on Page 1. Beneath all cleaned areas severe pitting was found. Pit depths ranged from 1/8" to 3/16". These values would not be reflected within the UT readings of Page 1.

All inspected welds exhibited preferential weld attack. This form of corrosion appears to have originated in original weld flaw (porosity holes) and has now expanded to affect the weld integrity.

External

The New Chelsea site has seen tremendous vegetation growth over the buried section of penstock. This type of growth is evidence of a moist/oxidized soil which will accelerate corrosion of the external surface. There were also two streams identified as running over and under the penstock. External surfaces were not made available for inspection but the variation in UT thickness values on Page 1 are indicative of a corroded external profile.

AREAS AT 2 O'CLOCK TO 10 O'CLOCK
POSITION VERY HEAVILY CORRODED/PITTED.



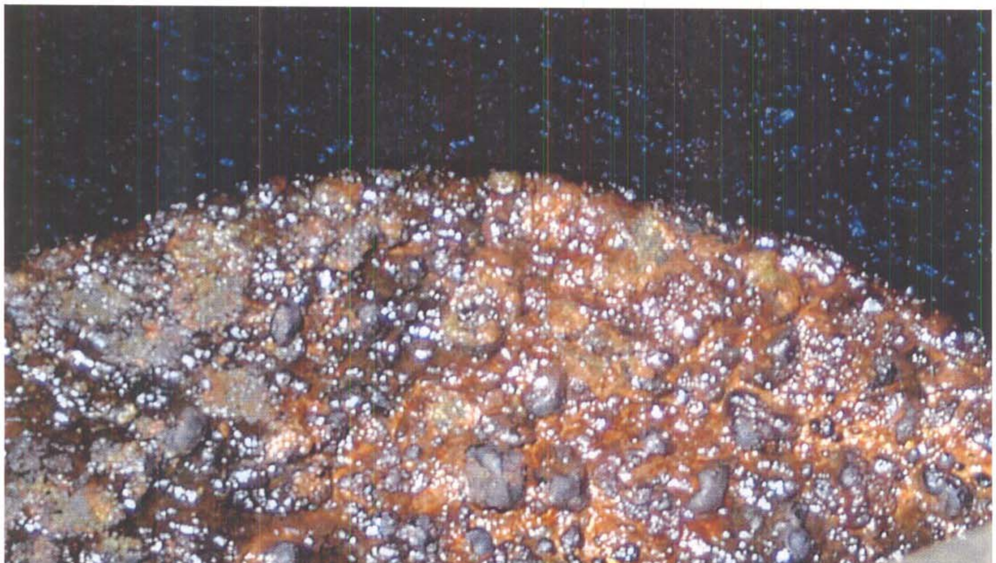
NOTE:
ULTRASONIC/VISUALS WERE APPROXIMATELY 4' APART.

TITLE				
NEWFOUNDLAND POWER NEW CHELSEA PENSTOCK				
JOB No.	DWG. No.	REV. No.	SCALE	DATE
330–24	SK1	A	N.T.S.	03.06.11 YY.MM.DD

fga - CANSPEC
MATERIALS ENGINEERING & TESTING

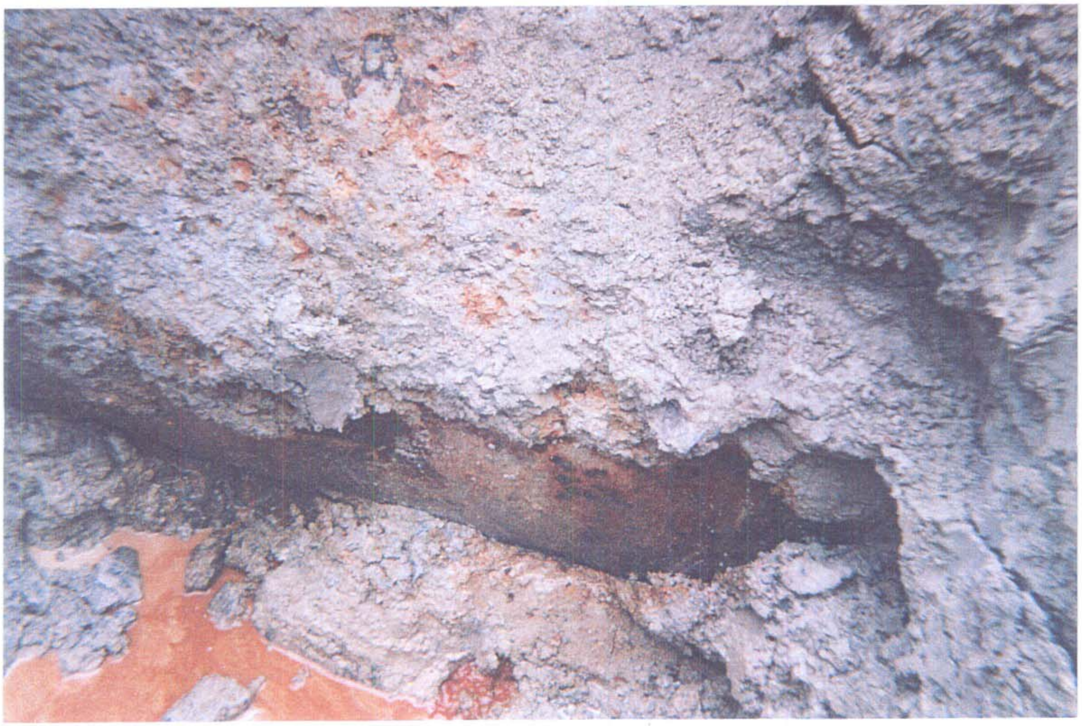
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753–2100 / Fax: (709) 753–7011

Pitting on Inside Surface of Manhole Cover



Growth on Internal Surface of Penstock

Penstock at Test Pit #1



Penstock at Test Pit #2

Penstock at Test Pit #3

Appendix E

Feasibility Analysis

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 25, 2003

Memorandum From: **Gary L. Murray**

To: **Gary Humby**

Subject: **New Chelsea Rehabilitation Projects – Feasibility Analysis**

File: **401.01.03.23.00**

We have completed a feasibility analysis on the continued operation of the New Chelsea hydroelectric development. Several major components of the development are in need of replacement or refurbishment, including the penstock, governor, protection & controls, main inlet valve, and generator. With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development over a 25-year horizon was warranted. A summary of the costs and benefits associated with this analysis follows.

Capital Costs

All significant capital expenditures foreseen for the hydroelectric development over the next 25 years have been identified. The majority of these expenditures are currently planned for 2004. The expenditures required to maintain the safe and reliable operation of the facilities are summarized below. A complete breakdown of capital costs and operating costs are provided in Schedule "A".

Description	Cost (2004 $)	Year of Expenditure	Cost (Escalated 1.7% Per Year)
Penstock Replacement - Woodstave	$1,735,000	2004	$1,735,600
Penstock Replacement - Steel	$500,000	2004	$500,000
Forebay Dam Rehab	$30,000	2004	$30,000
Electrical, Protection & Controls	$972,000	2004	$972,000
Main Inlet Valve Repalcement	$150,000	2004	$150,00
Refurbish Runner & Wicket Gates	$23,000	2004	$23,000
Generator Rewind	$400,000	2004	$400,000
Substation Modifications	$163,000	2004	$163,000
Intake Concrete Rehab	$50,000	2010	$55,300
Powerhouse Roof Replacement	$50,000	2010	$55,300
Spillway Concrete Rehab	$30,000	2010	$33,200
Transformer Replacement	$250,000	2024	$350,200
TOTAL	**$4,353,000**		**$4,467,600**

The total capital expenditure of all of the projects listed above is $4,353,000 (in 2004 dollar values). All estimates are also shown as escalated values using an assumed escalation rate of 1.7%.

Operating Costs

Operating costs for this hydroelectric system were based primarily upon recent years' operating experience. These costs represent both direct charges for operations and maintenance at this plant as well as indirect costs related to activities associated with managing the environment, safety, dam safety inspections, staff training, etc.

In addition to inflationary adjustments, operating costs are also increased by $0.50 per horsepower year water usage charges. This fee is paid annually to the Provincial Department of Environment (Water Resources Division) based on yearly hydroplant generation/output. Such a charge is not reflected in the historical annual operating costs for the New Chelsea development. Therefore, an adjustment is applied to account for this operating expense.

Penstock maintenance has accounted for a significant portion of the operating costs of this plant in recent years. Future operating cost has been estimated to include an assumed reduction of $5,000 per year to reflect the penstock replacement.

Benefits

The estimated long-term normal production at this plant under present operating conditions is 15.6 GWh/yr. This estimate is based on the results of the Water Management Study completed by Acres International Limited in December 2000. With an assumed station service adjustment of 0.1 GWh/yr, the normal plant output is estimated at 15.5 GWh/yr.

Some of the capital improvement projects will result in decreased energy losses (such as leakage from the woodstave penstock and less head losses in the new steel pipe) and subsequent increases in capacity and generation. The magnitude of these increases is difficult to estimate, but are not significant, so no allowance has been made for any increase in the forecasted generation at New Chelsea.

The downtime associated with the 2004 capital works at this plant will result in a higher amount of spill at the forebay compared to a normal operating year. It is anticipated that the potential lost generation may be in the order of 0.5 GWh. Therefore, the analysis assumed production at New Chelsea of 15.0 GWh in 2004, and 15.5 GWh/yr thereafter.

Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement required to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the New Chelsea plant over the next 25 years is 3.19 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. For comparative purposes the levelized cost was also calculated over 40 years and found to be 3.17 cents per kWh. The levelized cost of energy from New Chelsea can be produced at a lower price than the cost of replacement energy, assumed to come from Hydro's Holyrood Generating Station. Using Hydro's short term price forecast and an assumed fuel price escalation rate of 2% in the longer term, incremental energy from the Holyrood Generating Station is estimated to cost 5.53 cents per kWh, levelized over the same 25 year period. Energy from New Chelsea plant also compares favourably with 5.86 cents per kWh (2002 dollars) for the Rose Blanche Brook development and with marginal energy values implied by recent contracts entered into by Hydro with non-utility generators.

The future capacity benefits of the continued availability of New Chelsea hydro plant have not been considered in this analysis. In addition, decommissioning costs would be associated with any decision to shut down this facility and the financial benefit associated with the deferral of these costs has not been factored into this analysis.

Conclusions

It is concluded that operation of the New Chelsea hydroelectric development is economically viable over the long term. Based on the results of this feasibility analysis, it is recommended that the rehabilitation work proposed at New Chelsea for 2004 proceed as planned.

Schedule A
Summary of Capital Costs and Operating Costs

CAPITAL COSTS

Description	Cost (2004 $)	Year of Expenditure	Cost (Escalated 1.7% Per Year)
Civil			
Penstock Replacement - Woodstave	$1,735,000	2004	$1,735,600
Penstock Replacement - Steel	$500,000	2004	$500,000
Forebay Dam Rehab	$30,000	2004	$30,000
Intake Concrete Rehab	$50,000	2010	$55,300
Powerhouse Roof Replacement	$50,000	2010	$55,300
Spillway Concrete Rehab	$30,000	2010	$33,200
Subtotal Civil	**$2,395,000**		**$2,409,400**
Mech/Elec			
Governor/Protection & Controls	$972,000	2004	$972,000
Main Inlet Valve Repalcement	$150,000	2004	$150,000
Refurbish Runner & Wicket Gates	$23,000	2004	$23,000
Generator Rewind	$400,000	2004	$400,000
Substation Modifications	$163,000	2004	$163,000
Transformer Replacement	$250,000	2024	$350,200
Subtotal Mech/Elec	**$1,958,000**		**$2,058,200**
TOTAL	**$4,353,000**		**$4,467,600**

		Hydro 4% CCA	Hydro 30% CCA	Hydro TOTAL
0	2004	$2,238,000	$1,735,000	$3,973,000
1	2005			
2	2006			
3	2007			
4	2008			
5	2009			
6	2010	$143,800		$143,800
7	2011			
8	2012			
9	2013			
10	2014			
11	2015			
12	2016			
13	2017			
14	2018			
15	2019			
16	2020			
17	2021			
18	2022			
19	2023			
20	2024	$350,200		$350,200
21	2025			
22	2026			
23	2027			
24	2028			
25	2029			
	TOTAL	**$2,755,900**	**$1,735,000**	**$4,467,600**

OPERATING COSTS

Year	Amount
1989	$93,887
1990	$135,654
1991	$92,686
1992	$81,721
1993	$89,374
1994	$92,907
1995	$92,057
1996	$87,252
1997	$85,037
1998	$70,794
1999	$56,762
2000	$86,593
2001	$61,128
Average	$86,604

1989 to 2001 Average Operating Cost =	**$86,600**	
Water Use Charges =	**$1,700**	
Reduced Future Penstock Maintenance =	**$5,000**	(-ve)
Total Annual Operating Cost =	**$83,300**	

Appendix F

Budget Estimate

2004 Capital Budget Estimates

Description	Cost Estimate ($1,000s)
Penstock	$ 2,235,000.00
Forebay Dam Rehabilitation	$ 30,000.00
Electrical, Protection & Control	$ 972,000.00
Main Inlet Valve	$ 150,000.00
Refurbish Runner & Wicket Gates	$ 23,000.00
Rewind Generator	$ 400,000.00
Substation Modifications	$ 163,000.00
Total	**$ 3,973,000.00**

Project Title: **Rebuild Substations**

Location: **Grand Bay, Trepassey, Indian Cove, Port Blandford, Wheelers, Laurentian, Bay Roberts and Stamps Lane**

Classification: **Substations**

Project Cost: **$1,023,000**

This project consists of a number of items as noted.

(a) Grand Bay Site Modifications

Cost: $145,000

Description: This project involves enlarging the substation to provide the proper clearances for the new 2.5 MW portable diesel generator being acquired in 2003.

Operating Experience: There are presently 2 mobile diesel generators at Grand Bay substation, which are being retired in 2003. A new 2.5 MW unit being acquired in 2003 will be installed in their place and will provide additional backup generation for the area.

Justification: The overall project is justified based on improvement in the reliability of the electrical system.

(b) Trepassey Site Modifications

Cost: $145,000

Description: This project involves enlarging the substation to provide the proper clearances. This is required to accommodate the existing portable gas turbine (during emergencies) as well as for the new portable diesel generator unit to be acquired in 2004. See Volume I, Energy Supply, Schedule B, page 14, for more information on the new portable diesel generator unit.

Operating Experience: Trepassey has a peak load of approximately 3.3 MW and is supplied over a long radial transmission (95L). The new portable diesel generator unit has a capacity of 2.5 MW and can carry approximately 75 % of peak load. With 95L out of service power could be restored to Trepassey with little or no power rationing.

Justification: The overall project is justified based on improvement in the reliability of the electrical system.

(c) Indian Cove - Upgrade Structure / Transformer

Cost: $138,000

Description: This project involves replacing the 45 year old deteriorated 1.8 MVA, 25 kV to 12.5 kV stepdown transformer and structure at Indian Cove substation and to make improvements to the substation.

Indian Cove Substation

.

Operating Experience: Inspections have indicated that the power transformer and structure have deteriorated to the point of requiring replacement.

Justification: Due to equipment deterioration, there is a risk of power outages and oil spills.

(d) Port Blandford - Replace 138 kV Switches

Cost: $217,000

Description: Replace PBD-124-A6 and PBD-124L-A7 switches and structures with new switches and low profile steel structure. A 138kv dead-end structure will be placed in front of each switch location, and new switches will be installed on low profile steel structure.

Operating Experience: The two existing switches are under-built on wood pole structures and were placed in service in 1990. The switches are in constant need of adjustment due to the movement of the wood pole structures each time the switches are opened or closed. There have been occasions when the switches failed to properly break the electrical arc that occurs during switching, which has the potential to cause a fault on the transmission line. This in turn results in unplanned outages to customers and creates a safety hazard for the employees who operate the switches.

The switches are now tagged as “Out of Service” and will only be operated by first removing the power from 124L.

Port Blandford Switch

Justification: Improve reliability to customers when switching sections of 124L out of service for maintenance.

(e) Wheelers – Re-terminate Line

Cost: $85,000

Description: Install a new dead-end structure for 404L inside Wheelers substation, reterminate 404L to the existing airbreak switch 404L-A and install protective relaying at Gallants and Stephenville substations.

Operating Experience: Wheelers (WHE) is a deteriorated and obsolete substation that is past its useful life. The retermination of 404L along with changes to system protection at Gallants and Stephenville substations will allow the decommissioning of this station without compromising reliability or system performance.

Justification: Replacement of deteriorated substation and associated obsolete equipment. This will reduce maintenance costs and provide a more straightforward operating arrangement.

(f) Stamps' Lane - Power Cable Replacement

Cost: $95,000

Description: This project involves the replacement of power cables supplying T1 and T2 transformers.

Operating Experience: The cables at Stamps Lane substation were installed in 1958. These oil-insulated cables supply the 4 kV transformers.

In 2002, while maintaining the transformers, staff found that the cable terminations were leaking insulating compound and the metal bodies of the terminations were cracked. Maintenance staff determined that these cables are too deteriorated to allow the installation of new terminations. While neither cable has failed to date, this is most likely due to the low system voltage. Deterioration will continue and the cables will ultimately fail.

Justification: Replacement of deteriorated equipment to prevent outages to customers.

(g) Stamps Lane, Bay Roberts and Laurentian – Site and Foundation Upgrades

Cost: $120,000

Description: This work involves rectifying deteriorated concrete foundations, inadequate drainage and security/safety issues.

Operating Experience: The major item for this project in 2004 is the replacement and refurbishment work required at Stamps Lane and Bay Roberts in response to SGE Acres 2002 report on the condition of all substation concrete installations. In addition to these locations, work will be undertaken at the Laurentian substation yard to address drainage issues.

Justification: Structural and equipment concrete foundations/pads in many substations have deteriorated over time. There is varying degrees of deterioration evident within many substations. SGE Acres inspected all concrete installations in every substation and produced a prioritized list of installations which require replacement or refurbishment. The underlying causes of the deterioration are:

- Natural actions, such as freeze-thaw, thermal movement and shrinkage cracking.
- Mechanical damage such as impact or abrasion
- Chemical damage such as carbonation, sulphate attack and alkai-aggregate reactions.

The SGE Acres report details the deterioration and the type of remediation work required in each substation. The SGE Acres report was previously filed in response to Request for Information CA-20 (b), Attachment F in the Newfoundland Power 2003 Capital Budget Application.

(h) Projects < $50,000

The following is a list of projects estimated at less than $50,000.

1. Wesleyville – replace feeder disconnect switches
2. Glendale – replace underground cable with overhead conductor
3. Old Perlican – rectify safety clearance related to regulators
4. Trepassey – rectify safety clearance related to regulators
5. Long Lake – rectify safety clearance related to regulators

Project Title:	**Replacement & Standby Substation Equipment**
Location:	**Pepperell, Summerford, Milton, Bonavista, Glenwood, Boyd's Cove, Glovertown, Gambo, Laurentian, Gillams, Dunville, Cape Broyle, Greenhill and Mobile Substation P-435**
Classification:	**Substations**
Project Cost:	**$1,314,000**

This project consists of a number of items as noted.

(a) Deteriorated Breaker/Recloser Replacement

Cost: $300,000

Description: This project is part of an ongoing program to replace circuit breakers and reclosers that are deteriorated beyond economical repair.

In 2004 the 66 kV breaker at Pepperell and the 66 kV breaker at Summerford will be replaced.

Operating Experience: The Pepperell unit is 51 years old and its mechanism doesn't operate fast enough for the criteria required in the "Critical Clearing Time Study". It cannot be repaired due to the unavailability of parts. The Summerford unit is approximately 37 years old and its control circuitry does not operate consistently to ensure safe operation of the electrical system. The manufacturer's estimated cost to correct this problem is approximately equal to the cost of a new breaker.

Justification: This project is justified based on the need to replace equipment to maintain reliable and safe operation of the electrical system.

(b) Corporate Spares & Replacements

Cost: $600,000

Description: Purchase equipment to be used for corporate spares.

For 2004, the budgeted figure includes:

1 – 66 kV Circuit Breaker
1 – 15/25 kV Circuit Breaker
1 – 25 kV Electronic Recloser
3 – 138 kV Potential Transformers
3 – 66 kV Potential Transformers
3 – 15/25 kV Potential Transformers
3 – 15/25 kV 100 amp Voltage Regulators
9 – 15/25 kV 200 amp Voltage Regulators
10 – Universal Regulator Controls and Enclosures
1 – Model 210C Remote Telemetry Unit
2 – Transducers
4 – 48 Volt Battery Banks
1 – 120 Volt Battery Bank
3 – 48 Volt Battery Chargers
2 – 120 Volt Battery Chargers

This equipment is required to either replace equipment that fails in the field or to return corporate spares to appropriate levels.

Operating Experience: Every year the Company retires equipment due to vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence, failure during maintenance testing, excessive maintenance costs, etc. This equipment is essential to the integrity and reliability of the electrical supply to our customers and as such, the Company has to be able to replace "failed" equipment in a timely manner. Based on past operating experience, the above list is representative of what will need to be replaced in a typical year.

Justification: This project is justified on the basis of reliability in that this equipment is necessary to maintain service in a reliable, safe, environmentally sound manner. The following provides details on the major components to be acquired in 2004.

Circuit Breakers:

Newfoundland Power has approximately 400 circuit breakers in service. Breakers are used to switch transmission lines, transformers, feeders, generators and other equipment on and off the electrical system. In conjunction with protective relaying, they are used to isolate electrical faults. The majority of breakers are either transmission breakers (138 or 66 kV) or distribution breakers (typically 15 or 25 kV). The remainder are required in generation stations. The older breakers are often oil-filled and represent an environmental risk. By the nature of their operation, breakers will deteriorate and even though they are maintained, unexpected failures can occur.

Based on past experience, the Company maintains a pool of spare breakers to respond to these failures. This pool normally contains one 138 kV, two 66 kV and two 25 kV breakers. The 25 kV units can be installed in either 15 or 25 kV installations, thereby reducing the number of spares required. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for response to operational situations.

Electronic Reclosers:

The Company has approximately 200 reclosers in service. Reclosers allow switching of rural feeders, which carry lighter loads and have smaller electrical fault levels than urban feeders. They have built-in control units that sense electrical faults and operate the recloser to de-energize the feeder in the event of a fault.

The Company's older reclosers can be divided into four basic types – hydraulic, relay, resistor, and electronic, depending upon controller. The ability to isolate an electrical fault and their operational functionality increases in the order they are listed above. Therefore, as the electrical system has evolved, the units with lower functionality have fewer places where they can be installed.

Reclosers are replaced due to electrical/mechanical failure; severe physical deterioration; inability to provide adequate protection to a growing electrical system; and, parts obsolescence. In order to respond to these situations, the Company maintains a pool of spare reclosers. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for effective response to operational situations. The purchased unit will be an oil free, low maintenance and digitally controlled so that it is capable of replacing any other recloser and being integrated in to the SCADA system if the opportunity exists.

Potential Transformers (PTs):

The Company has approximately 220 PTs in-service. They measure voltage levels for input to protective relays, the SCADA system and metering circuitry. Failure of this equipment compromises the reliable operation of the electrical system. A failure can endanger staff and require clean up of a large area as oil can be sprayed over a 25 to 35 meter area. Each year unexpected PT replacements are required due to in-service failures. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for response to operational situations. Normally new units will be a *dry-type* design, eliminating the environmental risk associated with the older oil-filled units.

Voltage Regulators:

The Company has approximately 340 voltage regulators in service. These regulators are normally used to control voltages on long rural feeders.

The control units on voltage regulators have a service life of approximately 20 years. If they fail in service, the regulator becomes non-functional. These control units utilize obsolete electronic components and cannot be repaired. A universal replacement control unit enables the extension of the life of an older regulator for about 15% of the cost of a new regulator. These new control units are in stainless steel enclosures, thereby reducing corrosion. As well, they add increased functionality to the existing equipment, such as reverse power flow capability, more accurate voltage control and optional remote control capability. Based upon past experience and existing quantities, the budget number of 10 control units allows for the expected failure rate in the coming year.

The budget also includes replacement voltage regulators. These units are to replace units recently scrapped. The replacements will maintain the pool of spare voltage regulators at a level sufficient to respond to operational situations and maintenance programs. The new units can operate at 15 or 25 kV, allowing a reduction in the size of the pool. They also have stainless steel cases to reduce future corrosion related failures.

Direct Current Electrical Supply Systems (Batteries and Battery Chargers):

The substation DC power supplies provide electricity for equipment like protective relays, circuit breakers and reclosers, as well as provide emergency substation lighting.

The use of advanced battery testing methods has allowed the Company to adopt an approach whereby battery banks are replaced only when problems to a majority of batteries in the bank occur. Based upon past experience, the budget includes an allocation to replace battery banks as required.

Battery chargers are low maintenance, long life devices. The Company maintains a small pool of units to allow prompt replacement of failed units so as to ensure the security of its direct current electrical supplies. The units in the budget will allow for unexpected failures of battery chargers.

(c) Non-PCB Environmental Initiative

Cost: $175,000

Description: This is a long term program to replace equipment in substations which contain more than 50 PPM of PCB. This project will replace equipment such as substation service transformers, metering tanks and potential transformers. Often to accomplish the replacements, a portable substation will have to be installed.

In 2004, work will occur in Milton, Bonavista, Glenwood, Boyd's Cove and Glovertown substations.

Operating Experience: The Company has a large quantity of oil filled electrical equipment. Due to cross contamination, mineral oil in distribution transformers and other electrical equipment was inadvertently contaminated with PCB's at the manufacturing plant. Years ago transformer manufacturers used the same hoses and pumps to fill electrical equipment with PCB's and mineral oil. This resulted in some pieces of oil filled electrical equipment having 50 ppm PCB's or more. In other cases some equipment such as capacitors and ballasts were manufactured with pure PCB's.

The Company may experience spills from oil filled electrical equipment due to a number of reasons including rust, lightning, mechanical damage, storms, and human error. In the event of a spill, PCB's may be involved.

PCB spills can result in significant clean up costs. The general public and the environmental regulators also view PCB spills very negatively.

Justification: PCB's are synthetic chemical compounds consisting of chlorine, carbon and hydrogen. First synthesized in 1881, PCB's are relatively fire-resistant, very stable, do not conduct electricity and have low volatility at normal temperatures. PCB's were used for insulating fluid for electrical equipment, surface coatings for carbonless copy paper, as plasticizers in sealants, caulking, paints, waxes, asphalts, etc.

Unfortunately, one of the properties of PCB's which most contribute to their widespread use – their chemical stability – is also one of the properties which causes the greatest amount of environmental concern. This unusual persistence coupled with its tendency to accumulate in living organisms, means that PCB's are stored and concentrated in the environment. This bioaccumulation raises concern because of the wide dispersal of PCB's in the environment and the potential adverse effects they can have on various organisms. When PCB's are involved in fires the combustion of these materials can result in the production of highly toxic substances.

As a result of these concerns Government placed a ban on the manufacturing of PCB's in the late 1970's with further regulations established in the early 1980's. Under the regulations PCB's removed from equipment must be properly stored and disposed of in accordance with the regulations. There is also a requirement to report PCB spills, if one or more of the following conditions apply:

- The PCB concentration is 50 parts per million (ppm) or more by weight
- The quantity of PCB's released is 1 gram or more per day.

In the late 1980's the Company started to remove PCB's from its system and in the early 1990's a PCB phase out plan was implemented to ensure that the PCB level in equipment was below the permitted level of 50 ppm.

(d) Deteriorated Potential Transformer (PT) Replacement

Cost: $140,000

Description: This project involves the replacement of deteriorated high voltage potential transformers (PT) that are attached to substation high voltage buses. These units provide voltage level inputs into protective relaying, SCADA system and metering circuitry.

In 2004, three 66 kV PTs will be replaced in both Laurentian and Greenhill substations. The original PTs were installed in these substations in 1975.

Operating Experience: The amount of oil in a PT is small. Therefore any oil loss may compromise the insulation integrity of the PT and result in its failure. In the marine environment, to which substation equipment is exposed, rusting of metal components and subsequent loss of oil is an on-going issue. Since the beginning of 2001, twelve PTs, at five locations, were replaced due to rusting and oil leakage.

Greenhill and Laurentian substations have PTs from the same manufacturer. Several years ago, a PT failed in Laurentian due to the rusting of its top cover and water entering the PT. Also a PT in Greenhill had to be replaced due to rusting. The top covers of the other PTs in Greenhill and Laurentian were patched. Maintenance personnel are now concerned with the integrity of the patches and the likelihood of failure of those PTs.

Justification: PTs provide voltage level inputs for protective relaying, SCADA system and metering circuitry. Failure of these critical pieces of equipment compromises the safe operation of the electrical system.

(e) Recording Voltmeter Replacement

Cost: $59,000

Description: This project involves the replacement of recording broken voltmeters at Gillams, Dunville and Cape Broyle.

Operating Experience: The existing recording voltmeter has deteriorated beyond repair.

Justification: To properly manage the power system and to address voltage quality concerns monitoring of the low voltage bus is required. The recording voltmeter will provide this information to Newfoundland Power.

(f) Project < $50,000

The following project is estimated at less than $50,000.

1. Purchase a tandem axle dolley for use in transporting portable substation number P-435.

Project Title: **Feeder Additions Due To Load Growth and Reliability**

Location: **Chamberlains and Pulpit Rock Substations**

Classification: **Substations**

Project Cost: **$200,000**

This project consists of a number of items as noted.

(a) Chamberlains – Terminate New Feeder

Cost: $106,000

Description: This project involves the substation work associated with 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 the Kelligrews substation to the 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 in this area. (See Volume III, Distribution, Appendix 4, Attachment A)

(b) Pulpit Rock – Terminate New Feeder

Cost: $94,000

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

Operating Experience: Load growth in the Torbay area as well, the extended length of the feeder 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 in this area. (See Volume III, Distribution, Appendix 3, Attachment C)

Project Title: **Increase Corner Brook Transformer Capacity**

Location: **Walbournes and Bayview**

Classification: **Substations**

Project Cost: **$1,184,000**

(a) Walbournes – Replace T2

Description: Replace WAL-T2 transformer in Walbournes substation with a 25 MVA transformer. The existing 15 MVA unit will be removed and installed at Bayview substation.

Operating Experience: There are presently two power transformers at Walbournes substation and one power transformer at Bayview. WAL-T1 (20 MVA) is presently loaded to 95% of its capacity and WAL-T2 (15 MVA) is loaded to 111% of its capacity. The Bayview transformer is loaded to 110% of its capacity. The life expectancy of these units can be significantly reduced by continuous overloads.

The most cost effective solution is to replace the 15 MVA Walbournes unit (WAL-T2) with a 25 MVA transformer. The 15 MVA unit from Walbournes transformer will then be moved to the Bayview substation, where it will be installed as a second transformer. This transformer will reduce the loading on the existing unit, and allow sufficient capacity for load growth.

Justification: Two of the three transformers in these substations are presently overloaded. The life expectancy of these units can be significantly reduced by continuous overloads. A failure of one of these units would have a serious impact on reliability in the area.

Loss of the transformer at Bayview would mean an extended outage to all customers served from this substation. A portable transformer would have to be placed at Bayview until a suitable replacement unit can be obtained.

Loss of the overloaded unit at Walbournes would mean extended power outages in the form of power rationing for most customers served from this substation. The remaining unit would not have enough spare capacity to supply power to all customers. Power rationing would continue until a portable transformer could be installed to replace the failed unit. The portable would have to remain there until a suitable replacement unit can be obtained.
A copy of a planning study outlining the various alternatives and corrective action is contained in Volume II, Substations, Appendix 4, Attachment A.

Power Transformer Study

City of Corner Brook

Newfoundland Power Inc.

Power Transformer Study – Corner Brook

Appendices

Introduction

The purpose of this report is to provide a plan to meet the increasing electrical demand in the City of Corner Brook through increasing the City's limited substation transformer capacity. The 2003 Substation Load Forecast indicates that the total 12.5 kV load in the city will exceed the total 12.5 kV substation transformer capacity in 2004.

This study projects the electrical demands for the City of Corner Brook, develops alternatives to meet these demands, ensuring they meet minimum technical criteria. Further, an economic analysis for each alternative establishes the relative ranking of the alternatives with respect to customer revenue requirement. In conclusion the study recommends a preferred alternative.

Description of Existing System

Within the City of Corner Brook there are 3 substations: Bayview, Humber and Walbournes. These substations are supplied through 66 kV transmission lines from the Hydro in-feed substation at Massey Drive. Each substation has power transformers with a total of 5 among them. With the exception of replacements due to failure, the last new transformer was installed in 1977.

The power transformers are as follows:

Bayview Substation (BVS Sub)
- BVS-T1, 20 MVA, 12.5 kV, Installed in 1977

Walbournes Substation (WAL Sub)
- WAL-T1, 20 MVA, 12.5 kV, Installed in 1976
- WAL-T2, 15 MVA, 12.5 kV Installed in 1969

Humber Substation (HUM Sub)
- HUM-T2, 7.5 MVA, 4.16 kV, Installed in 1982
- HUM-T3, 13.3 MVA, 12.5 kV, Installed in 1974

HUM-T2 is a 4.16 kV unit and services 3 – 4.16 kV feeders within the city. Since there is no capacity constraint with respect to these 4.16

kV feeders, there is no plan to add 4.16 kV transformer capacity or to convert these feeders to 12.5 kV. These loads and the associated 4.16 kV transformer capacity are not included in the study.

The distribution system inside the city limits makes it possible to interconnect substations to avoid power outages by transferring loads between substations. In the past this has been used to limit outages to customers for planned work and major problems with the system. The distribution system also permits a second point of supply for critical customers like Western Memorial Regional Hospital. Since some power transformers will reach full capacity before others, these interconnecting feeders are used to manage the load until it rises to the total substation transformer capacity within the city.

A schematic diagram of the transmission and distribution systems supplying the area is shown in Figure 1.

Load Forecast and Growth Projections

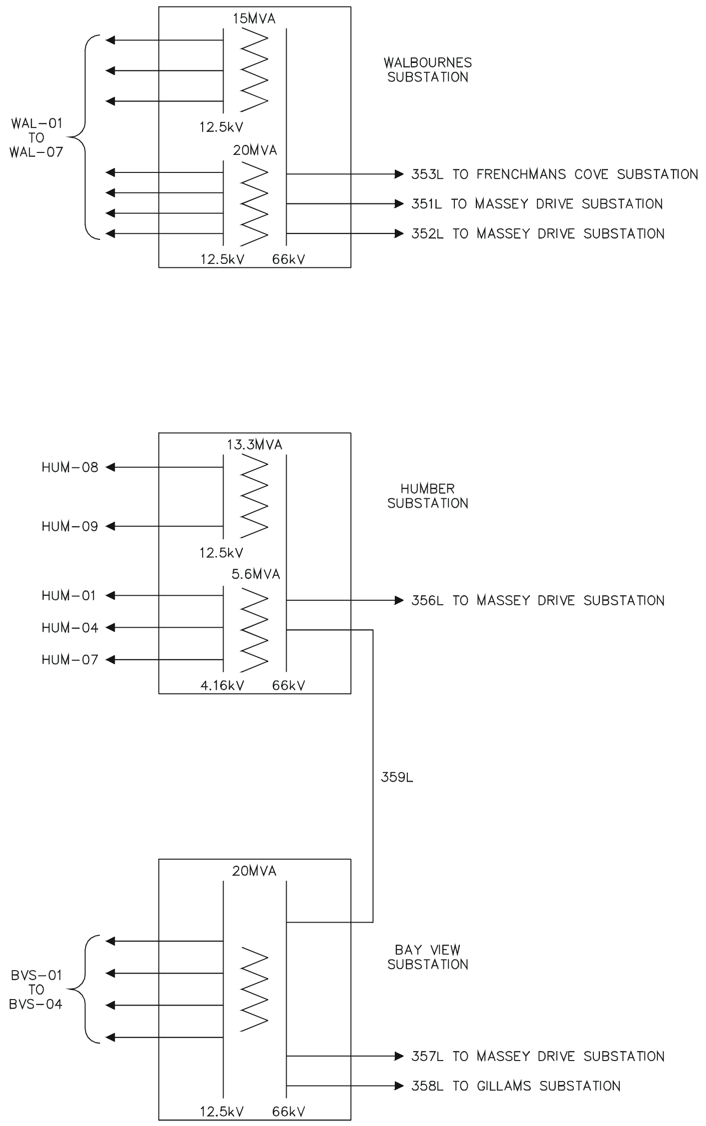
This study uses a 20-year Load Forecast for the power transformers within the city. The percent growth used is a combination of the “2003 Substation 5 Year Forecast” and guidance from the Director, Forecast within the Finance department. Appendix A, Page 1, contains a copy of the 5 Year Substation Forecast for the Corner Brook Area. Appendix A, Page 2, contains the 20-year load growth used in this study. Detailed load forecasts for each substation are also noted in Appendix B as part of the description of each alternative.

Development of Alternatives

Technical Criteria

The following technical criteria were considered pertinent to this study and to ensure acceptable operating conditions for the Corner Brook system:

1. The minimum steady state feeder voltage should not fall below 116 volts on a 120-volt base.



NEWFOUNDLAND POWER
A FORTIS COMPANY

CORNER BROOK 2003 POWER SYSTEM			
FIGURE 1			
Scale: N.T.S.	Drawn: 03.06.09	DWG. NO.	
Date: 03.07.03	App:		

2. The steady state power transformer loading should not exceed the nameplate rating.
3. The recloser normal peak loading should be sufficient to permit adequate cold load pickup.
4. the conductor loading should not exceed the ampacity rating established in the distribution planning guidelines.

Planning methodology and the Development of Alternatives

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 judgment factors. Based on this analysis a preferred alternative is recommended. As the load forecast extended to 2022, capital additions are projected over the same period.

In reviewing the substation load forecasts and comparing them to the associated substation transformer capacities, it is apparent that 12.5 kV substation transformer capacity will be exceeded in Corner Brook in 2004. Prior to considering alternatives to add transformer capacity, every effort was made to transfer load between substations and utilize whatever remaining capacity there might be at any substation. However, once the total load for the city's 12.5 kV feeders exceeds the capacity of the 12.5 KV transformer, there are no further options other than to add capacity. From the "2003 5 Year Substation Load Forecast", the total load within the city in 2004 will be 68.4 MVA while the total capacity is 68.3 MVA.

Three alternatives were developed that initially add 12.5 kV transformer capacity among the three Corner Brook substations. Each of the three alternatives uses a different location to add 2004 transformer capacity to the system. Using the load forecast, the load at each substation is established for a 20-year period. Effort is made to delay any additional transformers by using a combination of load transfers, additional feeders and down line equipment such as regulators. With increasing loads, as technical constraints are encountered in each alternative, projects are established to continue customer service and permit operation within the technical criteria.

Each alternative contains estimates for all costs involved including transformers, new feeders and load transfers. A present value calculation is provided for each alternative.

Alternative #1 - Install a new unit at Bayview Substation in 2004

Alternative #1 is the addition of a second, 25 MVA transformer at Bayview Substation in 2004 and an additional 25 MVA transformer at Walbournes in 2009. Feeder upgrades, transfers and additions are made when necessary.

Alternative # 1	**Cost**	**Year**
Add 25 MVA transformer at Baview / Load Transfers to Bayview from Walbournes & Humber / Feeder Upgrades	1,028,000	2004
Replace Walbournes T2 with 25 MVA Transformer	835,000	2009
Transfer Load from Walbounes to Humber & Upgrade Feeder	90,000	2010
Install New Feeder at Bayview	295,000	2012
Install New Feeder at Bayview with load transfers from Walbournes to Humber and Humber to Bayview	395,000	2019
Total Capital Cost	**2,643,000**	

Alternative #2 - Replace one of the existing units at Walbournes Substation and move it to Bayview in 2004

Alternative #2 is the replacement of one of the existing power transformers at Walbournes Substation in 2004 with a new 25 MVA unit. However, due to limits on the amount of load that can be transferred between Walbournes and Bayview, it is necessary to install additional capacity at Bayview. Accordingly, the unit removed from Walbournes will be installed in Bayview as BVS-T2 in 2004 to meet this requirement. The next transformer addition occurs in 2018 with an additional 25 MVA installed at Humber. Feeder upgrades, transfers and additions are made when necessary.

Alternative # 2	**Cost**	**Year**
Replace Walbournes T2 with a 25 MVA Transformer / Install transformer removed from Walbournes at Bayview	1,025,000	2004
Transfer Load from Humber to Bayview	15,000	2009
Transfer Load from Walbournes T1 to T2 and Feeder Upgrading	90,000	2010
Install New Feeder Bayview and feeder upgrading	295,000	2013
Replace Humber T3 with 25 MVA Transformer / Install New Feeder Humber / Transfer Load Walbournes to Humber	1,130,000	2018
Total Capital Cost	**2,555,000**	

Alternative #3 - Replace the existing transformer at Humber Substation in 2004

Alternative #3 is the replacement in 2004 of the existing 12.5 kV 13.3 MVA power transformer at Humber Substation with a new 25 MVA unit. In 2008 the 12.5 kV 15 MVA transformer at Humber is replaced with a 25 MVA transformer and in 2010 an additional 25 MVA transformer is added at Bayview . Feeder upgrades, transfers and additions are made when necessary. This option has the greatest overall substation transformer capacity at the end of the 20-year study.

Alternative # 3	Cost	Year
Replace Humber T3 with a 25 MVA transformer / Install New Feeder from Humber towards Bayview / Transfer load from Walbournes and Bayview to Humber	1,130,000	2004
Replace Walbournes T2 with 25 MVA Transformer	835,000	2008
Transfer Load from Walbournes T1 to T2 and upgrade feeders	90,000	2010
Install Additional 25 MVA Transformer at Bayview	780,000	2012
Install New feeder at Bayview / transfer load from Humber to Bayview / Upgrade feeders	295,000	2018
Total Capital Cost	**3,130,000**	

Economic Analysis

In order to compare the customer 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 detail of the projects associated with each alternative and the net present value calculations for each alternatives are shown in Appendix B.

In comparing the alternatives, all of which meet the technical criteria, alternative #2 is the lowest cost.

Alternative	Net Present Value Revenue Requirement ($)
1	2,312,236
2	2,034,380
3	2,465,195

Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End

Alternative #3 results in the largest overall transformer capacity existing in the study's last year. An analysis was completed to force all alternatives to have the same capacity in year 20. To complete this analysis, the cost of a power transformer was added in year 20 of the study to the other alternatives. This analysis is summarized in the following table, which indicates that alternative #2 again has the least present worth cost. The details of this analysis are contained in Appendix C, Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End.

Alternative	Net Present Value Revenue Requirement ($)
1	2,550,948
2	2,273,092
3	2,465,195

Conclusions and Recommendations

A 20-year load forecast has projected the electrical demands for the City of Corner Brook. The development and analysis of alternatives has established a preferred expansion plan to meet these needs. A further analysis has confirmed the validity of this alternative in adjusting the analysis for the unequal transformer capacity in the study's last year.

The lowest cost alternative that meets all of the technical criteria is alternative #2. It includes the 2004 replacement of the existing unit, Walbournes WAL-T2 transformer, with a new 25 MVA unit and moving the existing WAL-T2 unit to Bayview Substation in 2004. This scenario increases the transformer capacity of both substations. This alternative has the least present value costs, adds capacity in the known load growth areas and meets the technical criteria. It is therefore the preferred and recommended alternative.

Appendix A

Load Forecast

Western Region - Corner Brook Area
2003 Five Year Forecast

Substation (Notes)	Operating Des.	Transformer Voltage (kV)	Capacity (MVA) Rating	Capacity (MVA) Existing	2002 Peak (MVA)	Forecasted Undiversified Peak (MVA) 2003	2004	2005	2006	2007	2008	Max. Xfmr. Util.
Howley	T2	4.16	2.5/3.3/4	4.0	0.4	0.5	0.5	0.5	0.5	0.5	0.5	13%
Deer Lake	T1	12.47	10/13.3/16.7	16.7	15.0	15.6	15.3	15.4	15.5	15.5	15.6	94%
Marble Mountain	T1	12.47	3/4	4.0	3.0	3.3	3.2	3.1	3.2	3.2	3.2	83%
Pasadena	T1	12.47	10/13.3	13.3	7.3	8.7	8.6	8.8	8.9	9.0	9.1	69%
Bayview (3, 4 & 5)	T1	12.47	15/20	45.0	19.9	22.0	25.9	25.6	25.8	27.4	27.9	62%
Frenchmans Cove	T1	12.47	5/6.67	6.7	4.4	4.7	4.9	4.8	4.8	4.9	5.0	75%
Gillams	T1	12.47	5/6.67	6.7	4.6	5.0	5.1	5.1	5.1	5.2	5.3	79%
Humber	T2	4.16	5.6/7.46	7.5	5.0	5.4	5.5	5.5	5.5	5.6	5.7	76%
Humber	T3	12.47	10/13.3	13.3	10.9	11.8	12.1	12.0	12.1	12.3	12.5	94%
Walbournes	T1	12.47	15/20	20.0	16.1	17.9	18.4	18.1	18.3	18.6	19.0	95%
Walbournes (4 & 5)	T2	12.47	11.25/15	15.0	**15.0**	**16.6**	14.0	14.2	14.6	14.1	14.7	**111%**
TOTAL					**101.6**	**111.6**	**113.6**	**113.1**	**114.3**	**116.5**	**118.7**	

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) 2004 Additional 25MVA Transformer installed at Bayview.
(4) 2004 - 3MVA of load transferred from WAL-06 to BAY-04.
(5) 2007 - 1MVA of load transferred from WAL-06 to BAY-04.

Load Growth per Year
Forecasted Undiversified Peak

Year	Growth
2003	1.106
2004	1.030
2005	0.993
2006	1.012
2007	1.024
2008	1.024
2009	1.023
2010	1.022
2011	1.021
2012	1.020
2013	1.019
2014	1.018
2015	1.017
2016	1.016
2017	1.015
2018	1.015
2019	1.014
2020	1.013
2021	1.012
2022	1.011
2023	1.010

2003 to 2008 - 2003 5 year Substation Load Forecast
2009 to 2023 - Load growth in 2023 to be 1%. All other years prorated to this

Appendix B

Economic Analysis

APPENDIX B - ECONOMIC ALTERNATIVES – INTRODUCTION

For each of the three alternatives there follows a detailed listing of capital and operating expenditures. The reasons for each of these expenditures are noted and related to technical criteria or other requirements for expenditures to be made.

Following the detailed listing of capital and operating expenditures is a one page present worth economic analysis using the revenue requirement or customer cash flow methodology. Each capital cost is converted to a multi year stream of capital related revenue requirements extending over the life of the asset. Operating costs are also added to achieve the overall revenue requirement for each alternative in every year. This multi year revenue requirement is then discounted to the present using the average incremental cost of capital. It is this present worth amount for each alternative that is brought forward to the economic analysis section of the report's body.

One item of note in the present worth analysis sheets is the Deferment Benefits column. When an alterative indicates that a substation transformer is to be removed from the Corner Brook system, it is still of value to the Newfoundland Power electrical system. Its remaining life will be utilized in another substation. It is therefore important that when the transformer is shown as removed from an alternative, that the alternative be credited with the value of the remaining life of that transformer. The Deferment Benefit reflects the value of this remaining life.

Alternative #1 - Install New Unit at Bayview Substation in 2004

Transformer	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capital Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		25.0		13.3		20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.1	65.4%	13.1	52.3%	11.9	89.6%	18.3	91.7%	14.1	93.9%	1,028,000.00	600.00	(1)
2005	13.0	64.9%	13.0	52.0%	11.8	88.9%	18.2	91.0%	14.0	93.2%		600.00	
2006	13.1	65.7%	13.1	52.6%	12.0	90.0%	18.4	92.1%	14.2	94.3%		1796.00	
2007	13.5	67.3%	13.5	53.8%	12.3	92.1%	18.9	94.3%	14.5	96.6%		600.00	
2008	13.8	68.9%	13.8	55.1%	12.5	94.3%	19.3	96.5%	14.8	98.8%		600.00	
2009	14.1	70.4%	14.1	56.3%	12.8	96.4%	19.7	98.7%	15.2	60.6%	835,000.00	1796.00	(2)
2010	14.4	71.9%	14.4	57.6%	10.1	76.0%	17.2	85.8%	21.5	86.0%	90,000.00	600.00	(3)
2011	14.7	73.4%	14.7	58.8%	10.3	77.6%	17.5	87.6%	21.9	87.8%		600.00	
2012	15.0	74.9%	15.0	59.9%	10.5	79.1%	17.9	89.4%	22.4	89.5%	295,000.00	1796.00	(4)
2013	15.3	76.3%	15.3	61.1%	10.7	80.6%	18.2	91.1%	22.8	91.2%		600.00	
2014	15.5	77.7%	15.5	62.2%	10.9	82.1%	18.5	92.7%	23.2	92.9%		600.00	
2015	15.8	79.1%	15.8	63.2%	11.1	83.5%	18.9	94.3%	23.6	94.5%		8036.00	
2016	16.1	80.3%	16.1	64.3%	11.3	84.8%	19.2	95.9%	24.0	96.0%		600.00	
2017	16.3	81.6%	16.3	65.3%	11.5	86.1%	19.5	97.3%	24.4	97.5%		600.00	
2018	16.6	82.8%	16.6	66.2%	11.6	87.4%	19.8	98.8%	24.7	98.9%		1796.00	
2019	18.8	93.9%	18.8	75.1%	11.8	88.6%	18.0	90.1%	23.1	92.2%	395,000.00	600.00	(5)
2020	19.0	95.1%	19.0	76.1%	11.9	89.7%	18.2	91.2%	23.4	93.4%		600.00	
2021	19.2	96.2%	19.2	77.0%	12.1	90.8%	18.5	92.3%	23.6	94.5%		1796.00	
2022	19.5	97.3%	19.5	77.8%	12.2	91.8%	18.7	93.3%	23.9	95.5%		600.00	
2023	19.6	98.2%	19.6	78.6%	12.3	92.7%	18.9	94.3%	24.1	96.5%		600.00	

Notes:

(1) 2004 Load Changes

Additional 25 MVA Transformer installed at Bayview. (impedance match)	780,000.00
3 Mva transferred from WAL-T2 to BVS-T1	
0.5 MVA transferred from HUM-T3 to BVS-T1	
Upgrade the BVS-04 U/G Crossing at Confederation Drive.	65,000.00
Reconductor 6 spans along Golf Course,	5,000.00
Reframe pole O'Connell and West Valley,	8,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Install 1 – 1 Phase Regulator for Gallants line BVS-04	40,000.00
Install 1 – 3 Phase Regulator in Park	115,000.00
Total for 2004	1,028,000.00

(2) 2009 Load Changes

Replace WAL-T2 with 25 MVA transformer, Replace Cables	835,000.00

	Total for 2009	835,000.00
(3) 2010 Load Changes		
Replace WAL-03 Cables		75,000.00
3 Mva Transferred from WAL-T1 to WAL-T2		
3 Mva Transferred From HUM-T3 to WAL-T2		
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2010	90,000.00
(4) 2012 Load Changes		
Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2012	295,000.00
(5) 2019 Load changes:		
Build new feeder from BVS 12.5 bus - extend 12.5 kv bus		380,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
4 MVA transferred from HUM-T3 to BVS		
2 MVA transferred from WAL-T2 to HUM-T3		
2 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2019	395,000.00

(6) Additional Maintenance Cost per extra Transformer
$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Transfer WAL-06 up to and including Canada Games Centre
This transfer would offload the upper section of HUM-09. BVS-02 would feed through the cable at CNIB to the McPherson Hgts area. BVS-04 would need an aerial route to the golf course, along with the other items indicated to allow it to feed this load. This will load BVS-04 to 7 MVA and put the University and Canada Games Centre at risk of outages caused on the long Rural section of BVS-04.

(2) Without Transformer Changeout WAL-T2 would be at 101.1% in this year

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010
Without Transfer, HUM-T3 would be at 100.6% in 2011

(4) Necessary for loading at BVS. Without the new feeder, we would have 30 MVA on 4 feeders.

(5) Without Transformer Changeout / Transfer WAL-T2 would be at 101.1% in this year, WAL-T2 would be at 100.2%
This feeder would have to be Double Circuit through the town. It would pick up some load
from HUM-09 and HUM-09 would pick up load from WAL-T2 and WAL-T1.

(6) Based on current practices and pricing

Based on matched impedance Transformer at BVS in 2004

	Spare Capacity		
Year	**Available**	**Used**	**Spare**
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	103.3	77.5	25.8
2011	103.3	79.2	24.1
2012	103.3	80.7	22.6
2013	103.3	82.3	21.0
2014	103.3	83.8	19.5
2015	103.3	85.2	18.1
2016	103.3	86.6	16.7
2017	103.3	87.9	15.4
2018	103.3	89.2	14.1
2019	103.3	90.4	12.9
2020	103.3	91.6	11.7
2021	103.3	92.6	10.7
2022	103.3	93.7	9.6
2023	103.3	94.6	8.7

Present Worth Analysis Alternative #1 (Install New BVS-T2)

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	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth
	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								Benefit
	4% CCA	4% CCA	30% CCA	30% CCA	4% CCA	4% CCA	4% CCA	20% CCA								
2004						1,045,476			144,849	600	610	0		-145,460	-134,039	-134,039
2005									131,029	600	621	0		-131,650	-111,790	-245,829
2006									128,901	1,796	1,889	0		-130,790	-102,340	-348,169
2007									126,737	600	642	0		-127,379	-91,845	-440,014
2008									124,539	600	653	0		-125,192	-83,181	-523,196
2009						923,873			250,310	1,796	1,987	0	203,991	-48,306	-29,576	-552,772
2010						101,272			249,867	600	675	0		-250,542	-141,355	-694,127
2011									244,355	600	687	0		-245,042	-127,398	-821,525
2012						343,329			287,484	1,796	2,090	0		-289,575	-138,731	-960,256
2013									278,446	600	710	0		-279,156	-123,239	-1,083,495
2014									273,189	600	722	0		-273,911	-111,430	-1,194,925
2015									267,863	8,036	9,838	0		-277,701	-104,102	-1,299,027
2016									262,473	600	747	0		-263,220	-90,927	-1,389,954
2017									257,020	600	760	0		-257,780	-82,056	-1,472,010
2018									251,507	1,796	2,313	0		-253,820	-74,452	-1,546,463
2019						517,288			317,606	600	786	0		-318,392	-86,061	-1,632,523
2020									305,142	600	799	0		-305,942	-76,203	-1,708,726
2021									298,410	1,796	2,433	0		-300,843	-69,050	-1,777,776
2022									291,610	600	827	0		-292,436	-61,851	-1,839,627
2023									284,743	600	841	0		-285,584	-55,659	-1,895,286
2024									277,814	1,796	2,559	0		-280,373	-50,354	-1,945,640
2025									270,824	600	869	0		-271,694	-44,964	-1,990,604
2026									263,776	600	884	0		-264,660	-40,361	-2,030,965
2027									256,672	8,036	12,043	0		-268,716	-37,762	-2,068,727
2028									249,515	600	914	0		-250,429	-32,430	-2,101,157
2029									242,306	600	930	0		-243,236	-29,025	-2,130,182
2030									235,048	1,796	2,831	0		-237,879	-26,157	-2,156,339
2031									227,742	600	962	0		-228,704	-23,174	-2,179,513
2032									220,391	600	978	0		-221,370	-20,670	-2,200,183
2033									212,997	1,796	2,978	0		-215,975	-18,583	-2,218,766
2034									205,560	600	1,012	0		-206,572	-16,378	-2,235,144
2035									198,083	600	1,029	0		-199,112	-14,547	-2,249,691
2036									190,567	1,796	3,133	0		-193,700	-13,041	-2,262,732
2037									183,015	600	1,064	0		-184,079	-11,420	-2,274,152
2038									175,426	600	1,082	0		-176,509	-10,091	-2,284,243
2039									167,804	8,036	14,743	0		-182,547	-9,617	-2,293,860
2040									160,149	600	1,120	0		-161,268	-7,829	-2,301,688
2041									152,462	600	1,139	0		-153,600	-6,871	-2,308,559
2042									85,722	1,796	3,466	0		-89,188	-3,676	-2,312,236

Alternative #2 - Replace Walbournes T2 with 25 MVA Transformer

Transforme	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		15.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	13.2	66.0%	8.8	58.7%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.6	68.0%	9.1	60.4%	12.4	93.3%	18.3	91.7%	17.1	68.3%	1,025,000.00	600.00	(1)
2005	13.5	67.5%	9.0	60.0%	12.3	92.7%	18.2	91.0%	17.0	67.8%		600.00	
2006	13.7	68.3%	9.1	60.7%	12.5	93.8%	18.4	92.1%	17.2	68.7%		1796.00	
2007	14.0	69.9%	9.3	62.2%	12.8	96.0%	18.9	94.3%	17.6	70.3%		600.00	
2008	14.3	71.6%	9.5	63.6%	13.1	98.3%	19.3	96.5%	18.0	71.9%		600.00	
2009	15.8	79.2%	10.6	70.4%	11.4	85.4%	19.7	98.7%	18.4	73.6%	15,000.00	1796.00	(2)
2010	16.2	80.9%	10.8	71.9%	11.6	87.3%	17.2	85.8%	21.8	87.2%	90,000.00	600.00	(3)
2011	16.5	82.6%	11.0	73.4%	11.9	89.1%	17.5	87.6%	22.2	89.0%		600.00	
2012	16.8	84.2%	11.2	74.9%	12.1	90.9%	17.9	89.4%	22.7	90.7%		1796.00	
2013	17.2	85.8%	11.4	76.3%	12.3	92.6%	18.2	91.1%	23.1	92.5%	295,000.00	600.00	(4)
2014	17.5	87.4%	11.7	77.7%	12.5	94.3%	18.5	92.7%	23.5	94.2%		600.00	
2015	17.8	88.9%	11.9	79.0%	12.8	95.9%	18.9	94.3%	23.9	95.8%		8036.00	
2016	18.1	90.4%	12.0	80.3%	13.0	97.5%	19.2	95.9%	24.3	97.3%		600.00	
2017	18.4	91.8%	12.2	81.6%	13.2	99.0%	19.5	97.3%	24.7	98.8%		600.00	
2018	18.6	93.1%	12.4	82.7%	18.4	73.4%	17.3	86.3%	22.6	90.3%	1,130,000.00	1796.00	(5)
2019	18.9	94.4%	12.6	83.9%	18.6	74.4%	17.5	87.4%	22.9	91.5%		600.00	
2020	19.1	95.6%	12.7	84.9%	18.8	75.4%	17.7	88.5%	23.2	92.7%		600.00	
2021	19.3	96.7%	12.9	85.9%	19.1	76.3%	17.9	89.6%	23.4	93.8%		1796.00	
2022	19.5	97.7%	13.0	86.9%	19.3	77.1%	18.1	90.6%	23.7	94.8%		600.00	
2023	19.7	98.7%	13.2	87.7%	19.5	77.9%	18.3	91.5%	23.9	95.7%		600.00	

Notes:

(1) 2004 Load Changes

Replace WAL-T2 with 25 MVA unit, Replace WAL-T2 Cables		835,000.00
Install WAL-T2 (Existing) at BVS		190,000.00
	Total for 2004	1,025,000.00

(2) 2009 Load Changes:

Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 2 MVA from HUM-T3 to BVS		15,000.00
	Total for 2009	15,000.00

(3) 2010 Load Changes:

Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 4 MVA from WAL-T1 to WAL-T2		15,000.00
	Total for 2010	90,000.00

(4) 2013 Load Changes

Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2013	295,000.00

(5) 2018 Load changes:

Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
2.5 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2018	1,130,000.00

(6) Additional Maintanance Cost per extra Transformer

$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%

(2) Without Load transfer HUM-T3 will be at 100.5%

(3) Without Load transfer WAL-T1 will be at 100.8%

(4) Necessary for loading at BVS. Without the new feeder, we would have 28.6 MVA on 4 feeders.

(5) Because of the load sharing on the BVS XFMRs, there is no extra capacity at BVS. HUM-T3 will be replaced. If transfers are not complete - HUM-T3, 100.4% in 2018, WAL-T1 100.1% in 2019, WAL-T2 100.3% in 2018. New feeder required to handle load.

(6) Based on current practices and pricing

Based on Transformer to replace WAL-T2 in 2004
Installing WAL-T2 as BVS-T2 in 2004

Spare Capacity			
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	93.3	77.5	15.8
2011	93.3	79.2	14.1
2012	93.3	80.7	12.6
2013	93.3	82.3	11.0
2014	93.3	83.8	9.5
2015	93.3	85.2	8.1
2016	93.3	86.6	6.7
2017	93.3	87.9	5.4
2018	105.0	89.2	15.8
2019	105.0	90.4	14.6
2020	105.0	91.6	13.4
2021	105.0	92.6	12.4
2022	105.0	93.7	11.3
2023	105.0	94.6	10.4

Present Worth Analysis - Alternative #2 (Replace WAL-T2 with 25MVA)

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**	**Present Operating Costs**	**Escalated Operating Costs**	**Operating Benefits**	**Deferment Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**
2004						**1,042,425**			144,427	600	**610**	**0**		-145,037	-133,650	-133,650
2005									130,647	600	621	0		-131,268	-111,465	-245,115
2006									128,525	1,796	1,889	0		-130,414	-102,045	-347,160
2007									126,367	600	642	0		-127,009	-91,579	-438,739
2008									124,175	600	653	0		-124,828	-82,940	-521,679
2009						**16,597**			124,251	1,796	1,987	0		-126,238	-77,292	-598,970
2010						**101,272**			135,808	600	675	0		-136,483	-77,003	-675,974
2011									132,150	600	687	0		-132,837	-69,062	-745,036
2012									129,596	1,796	2,090	0		-131,686	-63,089	-808,125
2013						**349,166**			175,387	600	710	0		-176,097	-77,742	-885,866
2014									168,155	600	722	0		-168,878	-68,701	-954,568
2015									164,799	8,036	9,838	0		-174,637	-65,466	-1,020,034
2016									161,404	600	747	0		-162,151	-56,013	-1,076,048
2017									157,970	600	760	0		-158,730	-50,527	-1,126,574
2018						**1,455,100**			356,102	1,796	2,313	0	94,879	-263,536	-77,302	-1,203,877
2019									333,362	600	786	0		-334,148	-90,320	-1,294,196
2020									326,860	600	799	0		-327,659	-81,612	-1,375,809
2021									320,277	1,796	2,433	0		-322,710	-74,069	-1,449,878
2022									313,616	600	827	0		-314,442	-66,505	-1,516,383
2023									306,879	600	841	0		-307,720	-59,974	-1,576,356
2024									300,071	1,796	2,559	0		-302,629	-54,351	-1,630,707
2025									293,193	600	869	0		-294,062	-48,666	-1,679,373
2026									286,248	600	884	0		-287,133	-43,788	-1,723,161
2027									279,240	8,036	12,043	0		-291,284	-40,934	-1,764,095
2028									272,171	600	914	0		-273,085	-35,363	-1,799,458
2029									265,043	600	930	0		-265,973	-31,738	-1,831,196
2030									257,858	1,796	2,831	0		-260,690	-28,665	-1,859,862
2031									250,620	600	962	0		-251,582	-25,492	-1,885,354
2032									243,329	600	978	0		-244,307	-22,811	-1,908,165
2033									235,988	1,796	2,978	0		-238,966	-20,561	-1,928,726
2034									228,600	600	1,012	0		-229,612	-18,205	-1,946,931
2035									221,165	600	1,029	0		-222,194	-16,234	-1,963,165
2036									213,686	1,796	3,133	0		-216,819	-14,597	-1,977,762
2037									206,165	600	1,064	0		-207,229	-12,856	-1,990,619
2038									198,603	600	1,082	0		-199,686	-11,416	-2,002,035
2039									191,002	8,036	14,743	0		-205,746	-10,839	-2,012,873
2040									183,364	600	1,120	0		-184,483	-8,956	-2,021,829
2041									175,689	600	1,139	0		-176,828	-7,910	-2,029,739
2042									109,129	1,796	3,466	0		-112,595	-4,641	-2,034,380

Alternative #3 - Replace Humber T3 with 25 MVA Transformer

Transforme Size (MVA)	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
	20.0		25.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	17.7	88.3%	0.0	0.0%	19.9	79.7%	18.3	91.7%	14.6	97.2%	1,130,000.00		(1)
2005	17.5	87.7%	0.0	0.0%	19.8	79.1%	18.2	91.0%	14.5	96.5%			
2006	17.7	88.7%	0.0	0.0%	20.0	80.0%	18.4	92.1%	14.7	97.7%			
2007	18.2	90.8%	0.0	0.0%	20.5	81.9%	18.9	94.3%	15.0	100.0%			
2008	18.6	93.0%	0.0	0.0%	21.0	83.8%	19.3	96.5%	15.4	61.4%	835,000.00		(2)
2009	19.0	95.1%	0.0	0.0%	21.4	85.7%	19.7	98.7%	15.7	62.8%			
2010	19.4	97.1%	0.0	0.0%	21.9	87.6%	16.2	80.8%	20.0	80.2%	90,000.00		(3)
2011	19.8	99.2%	0.0	0.0%	22.4	89.4%	16.5	82.5%	20.5	81.8%			
2012	10.1	50.6%	10.1	40.5%	22.8	91.2%	16.8	84.2%	20.9	83.5%	780,000.00	600.00	(4)
2013	10.3	51.5%	10.3	41.2%	23.2	93.0%	17.2	85.8%	21.3	85.0%		600.00	
2014	10.5	52.5%	10.5	42.0%	23.7	94.6%	17.5	87.3%	21.6	86.6%		1796.00	
2015	10.7	53.4%	10.7	42.7%	24.1	96.3%	17.8	88.8%	22.0	88.1%		600.00	
2016	10.8	54.2%	10.8	43.4%	24.5	97.8%	18.1	90.3%	22.4	89.5%		600.00	
2017	11.0	55.1%	11.0	44.1%	24.8	99.3%	18.3	91.7%	22.7	90.9%		1796.00	
2018	13.7	68.4%	13.7	54.7%	20.2	80.8%	18.6	93.0%	23.1	92.2%	295,000.00	600.00	(5)
2019	13.9	69.3%	13.9	55.4%	20.5	81.9%	18.9	94.3%	23.4	93.5%		600.00	
2020	14.0	70.2%	14.0	56.2%	20.7	82.9%	19.1	95.5%	23.7	94.7%		1796.00	
2021	14.2	71.0%	14.2	56.8%	21.0	83.9%	19.3	96.6%	23.9	95.8%		600.00	
2022	14.4	71.8%	14.4	57.4%	21.2	84.8%	19.5	97.6%	24.2	96.8%		600.00	
2023	14.5	72.5%	14.5	58.0%	21.4	85.7%	19.7	98.6%	24.4	97.8%		8036.00	

Notes:

Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus to BVS-03 North Street - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
5 MVA transferred from BVS-T1 to HUM-T3		
	Total for 2004	1,130,000.00

(2) 2008 Load changes:

Replace WAL-T2 25 MVA unit, Replace WAL-T2 Cables		835,000.00
	Total for 2008	835,000.00

(3) 2010 Load Changes:

Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
4 MVA from WAL-T1 to WAL-T2		

	Total for 2010	90,000.00
(4) 2012 Load Changes:		
Additional 25MVA Transformer installed at Bayview. (Impedance Match)		780,000.00
	Total for 2012	780,000.00
(5) 2018 Load changes:		
Install New Feeder at BVS		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
5 MVA from HUM-T3 to BVS		
	Total for 2018	295,000.00

(6) Additional Maintenance Cost per extra Transformer
$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%. New feeder needed to handle additional load.

(2) If not completed load on WAL-T2 102.3% in 2008

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010

(4) Without Transfer, BVS-T1 would be at 101.1% in 2012

(5) Without Transfer, HUM-T3 would be at 100.8% in 2018

(6) Based on current practices and pricing

Based on Transformer to replace HUM-T3 2004

	Spare Capacity		
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	80.0	70.5	9.5
2005	80.0	70.0	10.0
2006	80.0	70.8	9.2
2007	80.0	72.5	7.5
2008	90.0	74.2	15.8

2009	90.0	75.9	14.1
2010	90.0	77.5	12.5
2011	90.0	79.2	10.8
2012	115.0	80.7	34.3
2013	115.0	82.3	32.7
2014	115.0	83.8	31.2
2015	115.0	85.2	29.8
2016	115.0	86.6	28.4
2017	115.0	87.9	27.1
2018	115.0	89.2	25.8
2019	115.0	90.4	24.6
2020	115.0	91.6	23.4
2021	115.0	92.6	22.4
2022	115.0	93.7	21.3
2023	115.0	94.6	20.4

Present Worth Analysis Alternative #3 (Replace HUM-T1)

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

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE															
	Generation	**Generation**	**Generation**	**Generation**	**Transmission**	**Substation**	**Distribution**	**Telecommunication**	**Capital Revenue Requirement**	**Present Operating Costs**	**Escalated Operating Costs**	**Operating Benefits**	**Deferment Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth**
	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								**Benefit**
	4% CCA	4% CCA	30% CCA	30% CCA	4% CCA	4% CCA	4% CCA	20% CCA								
YEAR																
2004						1,149,210			159,222	600	610	0	315,061	155,229	143,042	143,042
2005									144,030	600	621	0		-144,651	-122,829	20,213
2006									141,690	1,796	1,889	0		-143,580	-112,348	-92,135
2007									139,312	600	642	0	228,884	88,930	64,123	-28,012
2008						908,430			262,758	600	653	0		-263,410	-175,018	-203,030
2009									248,298	1,796	1,987	0		-250,285	-153,241	-356,272
2010						101,272			257,993	600	675	0		-258,668	-145,940	-502,212
2011									252,255	600	687	0		-252,942	-131,505	-633,717
2012						907,785			373,361	1,796	2,090	0		-375,451	-179,873	-813,589
2013									356,632	600	710	0		-357,343	-157,756	-971,346
2014									349,996	600	722	0		-350,718	-142,676	-1,114,022
2015									343,271	8,036	9,838	0		-353,109	-132,371	-1,246,392
2016									336,463	600	747	0		-337,210	-116,486	-1,362,878
2017									329,573	600	760	0		-330,333	-105,151	-1,468,029
2018						379,871			375,236	1,796	2,313	0		-377,549	-110,746	-1,578,775
2019									363,173	600	786	0		-363,958	-98,377	-1,677,152
2020									355,285	600	799	0		-356,084	-88,692	-1,765,844
2021									347,317	1,796	2,433	0		-349,749	-80,275	-1,846,120
2022									339,269	600	827	0		-340,096	-71,931	-1,918,050
2023									331,147	600	841	0		-331,988	-64,703	-1,982,754
2024									322,953	1,796	2,559	0		-325,511	-58,460	-2,041,214
2025									314,689	600	869	0		-315,558	-52,223	-2,093,437
2026									306,358	600	884	0		-307,242	-46,855	-2,140,292
2027									297,964	8,036	12,043	0		-310,007	-43,565	-2,183,857
2028									289,508	600	914	0		-290,423	-37,609	-2,221,466
2029									280,994	600	930	0		-281,924	-33,642	-2,255,107
2030									272,423	1,796	2,831	0		-275,254	-30,267	-2,285,374
2031									263,798	600	962	0		-264,760	-26,827	-2,312,202
2032									255,120	600	978	0		-256,099	-23,912	-2,336,114
2033									246,393	1,796	2,978	0		-249,371	-21,456	-2,357,570
2034									237,618	600	1,012	0		-238,630	-18,920	-2,376,490
2035									228,796	600	1,029	0		-229,825	-16,791	-2,393,282
2036									219,931	1,796	3,133	0		-223,063	-15,018	-2,408,299
2037									211,023	600	1,064	0		-212,087	-13,158	-2,421,457
2038									202,074	600	1,082	0		-203,156	-11,614	-2,433,071
2039									193,086	8,036	14,743	0		-207,829	-10,948	-2,444,020
2040									184,060	600	1,120	0		-185,180	-8,989	-2,453,009
2041									174,998	600	1,139	0		-176,137	-7,879	-2,460,888
2042									101,023	1,796	3,466	0		-104,489	-4,307	-2,465,195

Appendix C

Economic Analysis - Adjusting For Unequal Transformer Capacity at Study End

APPENDIX C - Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End – Introduction

It is important that all alternatives have comparable transformer at the end point of the study. It is not appropriate that one alternative has much more transformer capacity at the end time of the study, and therefore accrues disproportionate cost. In order that all alternatives end with the same transformer capacity, an adjustment is made in the alternatives to ensure this is the case.

In this study, alternative #3 has much more transformer capacity at the end of the study than do the other two alternatives. In order to make the alternatives comparable, Appendix C adds transformer capacity added with associated costs incurred to bring the alternatives to the same capacity / cost base.

Similar to Appendix B, details of expenditures and present worth analysis follow for each of the alternatives with the exception of alternative #3. The present worth of these alternatives is brought forward to the table in the body of the report. Adjusting for Unequal transformer Capacity at Study End, as is the present worth for alternative #3 noted in Appendix B.

Alternative #1 - Add Transformer at BVS - Adjust for Unequal Transformer Capacity

Transforme	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capital Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		25.0		13.3		20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.1	65.4%	13.1	52.3%	11.9	89.6%	18.3	91.7%	14.1	93.9%	1,028,000.00	600.00	(1)
2005	13.0	64.9%	13.0	52.0%	11.8	88.9%	18.2	91.0%	14.0	93.2%		600.00	
2006	13.1	65.7%	13.1	52.6%	12.0	90.0%	18.4	92.1%	14.2	94.3%		1796.00	
2007	13.5	67.3%	13.5	53.8%	12.3	92.1%	18.9	94.3%	14.5	96.6%		600.00	
2008	13.8	68.9%	13.8	55.1%	12.5	94.3%	19.3	96.5%	14.8	98.8%		600.00	
2009	14.1	70.4%	14.1	56.3%	12.8	96.4%	19.7	98.7%	15.2	60.6%	835,000.00	1796.00	(2)
2010	14.4	71.9%	14.4	57.6%	10.1	76.0%	17.2	85.8%	21.5	86.0%	90,000.00	600.00	(3)
2011	14.7	73.4%	14.7	58.8%	10.3	77.6%	17.5	87.6%	21.9	87.8%		600.00	
2012	15.0	74.9%	15.0	59.9%	10.5	79.1%	17.9	89.4%	22.4	89.5%	295,000.00	1796.00	(4)
2013	15.3	76.3%	15.3	61.1%	10.7	80.6%	18.2	91.1%	22.8	91.2%		600.00	
2014	15.5	77.7%	15.5	62.2%	10.9	82.1%	18.5	92.7%	23.2	92.9%		600.00	
2015	15.8	79.1%	15.8	63.2%	11.1	83.5%	18.9	94.3%	23.6	94.5%		8036.00	
2016	16.1	80.3%	16.1	64.3%	11.3	84.8%	19.2	95.9%	24.0	96.0%		600.00	
2017	16.3	81.6%	16.3	65.3%	11.5	86.1%	19.5	97.3%	24.4	97.5%		600.00	
2018	16.6	82.8%	16.6	66.2%	11.6	87.4%	19.8	98.8%	24.7	98.9%		1796.00	
2019	18.8	93.9%	18.8	75.1%	11.8	88.6%	18.0	90.1%	23.1	92.2%	395,000.00	600.00	(5)
2020	19.0	95.1%	19.0	76.1%	11.9	89.7%	18.2	91.2%	23.4	93.4%		600.00	
2021	19.2	96.2%	19.2	77.0%	12.1	90.8%	18.5	92.3%	23.6	94.5%		1796.00	
2022	19.5	97.3%	19.5	77.8%	12.2	91.8%	18.7	93.3%	23.9	95.5%		600.00	
2023	19.6	98.2%	19.6	78.6%	12.3	92.7%	18.9	94.3%	24.1	96.5%	780,000.00	600.00	(7)

(1) 2004 Load changes:

Additional 25 MVA Transformer installed at Bayview. (impedance match)	780,000.00
3 Mva transferred from WAL-T2 to BVS-T1	
0.5 MVA transferred from HUM-T3 to BVS-T1	
Upgrade the BVS-04 U/G Crossing at Confederation Drive.	65,000.00
Reconductor 6 spans along Golf Course,	5,000.00
Reframe pole O'Connell and West Valley,	8,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Install 1 – 1 Phase Regulator for Gallants line BVS-04	40,000.00
Install 1 – 3 Phase Regulator in Park	115,000.00
Total for 2004	1,028,000.00

(2) 2009 Load Changes

Replace WAL-T2 with 25 MVA transformer, Replace Cables	835,000.00

Total for 2009	835,000.00
(3) 2010 Load Changes	
Replace WAL-03 Cables	75,000.00
3 Mva Transferred from WAL-T1 to WAL-T2	
3 Mva Transferred From HUM-T3 to WAL-T2	
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Total for 2010	90,000.00
(4) 2012 Load Changes	
Install New Feeder BVS and Extend Bus	280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Total for 2012	295,000.00
(5) 2019 Load changes:	
Build new feeder from BVS 12.5 bus - extend 12.5 kv bus	380,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000	15,000.00
4 MVA transferred from HUM-T3 to BVS	
2 MVA transferred from WAL-T2 to HUM-T3	
2 MVA transferred from WAL-T1 to HUM-T3	
Total for 2019	395,000.00
(6) Additional Maintenance Cost per extra Transformer	
$600 per year - Oil Testing	
One Maint III every two years - 2 man crew - 2 Days - $1196	
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436	
(7) Additional Transformer added for Sensitivity Analysis	780,000.00
	780,000.00

Reasoning

(1) Transfer WAL-06 up to and including Canada Games Centre
This transfer would offload the upper section of HUM-09. BVS-02 would feed through the cable at CNIB to the McPherson Hgts area. BVS-04 would need an aerial route to the golf course, along with the other items indicated to allow it to feed this load. This

(2) Without Transformer Changeout WAL-T2 would be at 101.1% in this year

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010
Without Transfer, HUM-T3 would be at 100.6% in 2011

(4) Necessary for loading at BVS. Without the new feeder, we would have 30 MVA on 4 feeders.

(5) Without Transformer Changeout / Transfer WAL-T2 would be at 101.1% in this year, WAL-T2 would be at 100.2%
This feeder would have to be Double Circuit through the town. It
would pick up some load from HUM-09 and HUM-09 would pick up
load from WAL-T2 and WAL-T1.

(6) Based on current practices and pricing

Based on matched impedance Transformer at BVS in 2004

	Spare Capacity		
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	103.3	77.5	25.8
2011	103.3	79.2	24.1
2012	103.3	80.7	22.6
2013	103.3	82.3	21.0
2014	103.3	83.8	19.5
2015	103.3	85.2	18.1
2016	103.3	86.6	16.7
2017	103.3	87.9	15.4
2018	103.3	89.2	14.1
2019	103.3	90.4	12.9
2020	103.3	91.6	11.7
2021	103.3	92.6	10.7
2022	103.3	93.7	9.6
2023	115.0	94.6	20.4

Present Worth Analysis (Install New BVS-T2 Sensitivity 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	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment 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						1,045,476			144,849	600	610	0		-145,460	-134,039	-134,039
2005									131,029	600	621	0		-131,650	-111,790	-245,829
2006									128,901	1,796	1,889	0		-130,790	-102,340	-348,169
2007									126,737	600	642	0		-127,379	-91,845	-440,014
2008									124,539	600	653	0		-125,192	-83,181	-523,196
2009						923,873			250,310	1,796	1,987	0	203,991	-48,306	-29,576	-552,772
2010						101,272			249,867	600	675	0		-250,542	-141,355	-694,127
2011									244,355	600	687	0		-245,042	-127,398	-821,525
2012						343,329			287,484	1,796	2,090	0		-289,575	-138,731	-960,256
2013									278,446	600	710	0		-279,156	-123,239	-1,083,495
2014									273,189	600	722	0		-273,911	-111,430	-1,194,925
2015									267,863	8,036	9,838	0		-277,701	-104,102	-1,299,027
2016									262,473	600	747	0		-263,220	-90,927	-1,389,954
2017									257,020	600	760	0		-257,780	-82,056	-1,472,010
2018									251,507	1,796	2,313	0		-253,820	-74,452	-1,546,463
2019						517,288			317,606	600	786	0		-318,392	-86,061	-1,632,523
2020									305,142	600	799	0		-305,942	-76,203	-1,708,726
2021									298,410	1,796	2,433	0		-300,843	-69,050	-1,777,776
2022									291,610	600	827	0		-292,436	-61,851	-1,839,627
2023						1,092,732			436,140	600	841	0	47,770	-389,211	-75,856	-1,915,483
2024									414,766	1,796	2,559	0		-417,325	-74,950	-1,990,432
2025									405,551	600	869	0		-406,421	-67,261	-2,057,693
2026									396,241	600	884	0		-397,126	-60,562	-2,118,255
2027									386,840	8,036	12,043	0		-398,884	-56,055	-2,174,310
2028									377,352	600	914	0		-378,266	-48,984	-2,223,294
2029									367,779	600	930	0		-368,709	-43,998	-2,267,292
2030									358,126	1,796	2,831	0		-360,957	-39,691	-2,306,982
2031									348,395	600	962	0		-349,357	-35,399	-2,342,382
2032									338,590	600	978	0		-339,568	-31,706	-2,374,088
2033									328,713	1,796	2,978	0		-331,691	-28,539	-2,402,627
2034									318,768	600	1,012	0		-319,780	-25,354	-2,427,981
2035									308,757	600	1,029	0		-309,786	-22,633	-2,450,614
2036									298,683	1,796	3,133	0		-301,815	-20,320	-2,470,934
2037									288,548	600	1,064	0		-289,612	-17,967	-2,488,902
2038									278,355	600	1,082	0		-279,437	-15,975	-2,504,877
2039									268,106	8,036	14,743	0		-282,849	-14,901	-2,519,777
2040									257,803	600	1,120	0		-258,923	-12,569	-2,532,346
2041									247,449	600	1,139	0		-248,588	-11,120	-2,543,466
2042									178,022	1,796	3,466	0		-181,488	-7,481	-2,550,948

Alternative #2 - Add Transformer at WAL - Adjust for Unequal Transformer Capacity

Transforme	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		15.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	13.2	66.0%	8.8	58.7%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.6	68.0%	9.1	60.4%	12.4	93.3%	18.3	91.7%	17.1	68.3%	1,025,000.00	600.00	(1)
2005	13.5	67.5%	9.0	60.0%	12.3	92.7%	18.2	91.0%	17.0	67.8%		600.00	
2006	13.7	68.3%	9.1	60.7%	12.5	93.8%	18.4	92.1%	17.2	68.7%		1796.00	
2007	14.0	69.9%	9.3	62.2%	12.8	96.0%	18.9	94.3%	17.6	70.3%		600.00	
2008	14.3	71.6%	9.5	63.6%	13.1	98.3%	19.3	96.5%	18.0	71.9%		600.00	
2009	15.8	79.2%	10.6	70.4%	11.4	85.4%	19.7	98.7%	18.4	73.6%	15,000.00	1796.00	(2)
2010	16.2	80.9%	10.8	71.9%	11.6	87.3%	17.2	85.8%	21.8	87.2%	90,000.00	600.00	(3)
2011	16.5	82.6%	11.0	73.4%	11.9	89.1%	17.5	87.6%	22.2	89.0%		600.00	
2012	16.8	84.2%	11.2	74.9%	12.1	90.9%	17.9	89.4%	22.7	90.7%		1796.00	
2013	17.2	85.8%	11.4	76.3%	12.3	92.6%	18.2	91.1%	23.1	92.5%	295,000.00	600.00	(4)
2014	17.5	87.4%	11.7	77.7%	12.5	94.3%	18.5	92.7%	23.5	94.2%		600.00	
2015	17.8	88.9%	11.9	79.0%	12.8	95.9%	18.9	94.3%	23.9	95.8%		8036.00	
2016	18.1	90.4%	12.0	80.3%	13.0	97.5%	19.2	95.9%	24.3	97.3%		600.00	
2017	18.4	91.8%	12.2	81.6%	13.2	99.0%	19.5	97.3%	24.7	98.8%		600.00	
2018	18.6	93.1%	12.4	82.7%	18.4	73.4%	17.3	86.3%	22.6	90.3%	1,130,000.00	1796.00	(5)
2019	18.9	94.4%	12.6	83.9%	18.6	74.4%	17.5	87.4%	22.9	91.5%		600.00	
2020	19.1	95.6%	12.7	84.9%	18.8	75.4%	17.7	88.5%	23.2	92.7%		600.00	
2021	19.3	96.7%	12.9	85.9%	19.1	76.3%	17.9	89.6%	23.4	93.8%		1796.00	
2022	19.5	97.7%	13.0	86.9%	19.3	77.1%	18.1	90.6%	23.7	94.8%		600.00	
2023	19.7	98.7%	13.2	87.7%	19.5	77.9%	18.3	91.5%	23.9	95.7%	780,000.00	600.00	(7)

Notes

(1) 2004 Load changes:		
Replace WAL-T2 with 25 MVA unit, Replace WAL-T2 Cables		835,000.00
Install WAL-T2 (Existing) at BVS		190,000.00
	Total for 2004	1,025,000.00
(2) 2009 Load Changes:		
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 2 MVA from HUM-T3 to BVS		15,000.00
	Total for 2009	15,000.00
(3) 2010 Load Changes:		
Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 4 MVA from WAL-T1 to WAL-T2		15,000.00

	Total for 2010	90,000.00
(4) 2013 Load Changes		
Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2013	295,000.00
(5) 2018 Load changes:		
Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
2.5 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2018	1,130,000.00
(6) Additional Maintanance Cost per extra Transformer		
$600 per year - Oil Testing		
One Maint III every two years - 2 man crew - 2 Days - $1196		
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436		
(7) Additional Transformer added for Sensitivity Analysis		780,000.00
		780,000.00

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%

(2) Without Load transfer HUM-T3 will be at 100.5%

(3) Without Load transfer WAL-T1 will be at 100.8%

(4) Necessary for loading at BVS. Without the new feeder, we would have 28.6 MVA on 4 feeders.

(5) Because of the load sharing on the BVS XFMRs, there is no extra capacity at BVS. HUM-T3 will be replaced. If transfers are not complete - HUM-T3, 100.4% in 2018, WAL-T1 100.1% in 2019, WAL-T2 100.3% in 2018. New feeder required to handle load.

(6) Based on current practices and pricing

Based on Transformer to replace WAL-T2 in 2004
Installing WAL-T2 as BVS-T2 in 2004

	Spare Capacity		
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	93.3	77.5	15.8
2011	93.3	79.2	14.1
2012	93.3	80.7	12.6
2013	93.3	82.3	11.0
2014	93.3	83.8	9.5
2015	93.3	85.2	8.1
2016	93.3	86.6	6.7
2017	93.3	87.9	5.4
2018	105.0	89.2	15.8
2019	105.0	90.4	14.6
2020	105.0	91.6	13.4
2021	105.0	92.6	12.4
2022	105.0	93.7	11.3
2023	115.0	94.6	20.4

Present Worth Analysis (Replace WAL-T2 with 25MVA - Sensitivity 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	Present Operating Costs	Future Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004						1,042,425			144,427	600	610	0		-145,037	-133,650	-133,650
2005									130,647	600	621	0		-131,268	-111,465	-245,115
2006									128,525	1,796	1,889	0		-130,414	-102,045	-347,160
2007									126,367	600	642	0		-127,009	-91,579	-438,739
2008									124,175	600	653	0		-124,828	-82,940	-521,679
2009						16,597			124,251	1,796	1,987	0		-126,238	-77,292	-598,970
2010						101,272			135,808	600	675	0		-136,483	-77,003	-675,974
2011									132,150	600	687	0		-132,837	-69,062	-745,036
2012									129,596	1,796	2,090	0		-131,686	-63,089	-808,125
2013						349,166			175,387	600	710	0		-176,097	-77,742	-885,866
2014									168,155	600	722	0		-168,878	-68,701	-954,568
2015									164,799	8,036	9,838	0		-174,637	-65,466	-1,020,034
2016									161,404	600	747	0		-162,151	-56,013	-1,076,048
2017									157,970	600	760	0		-158,730	-50,527	-1,126,574
2018						1,455,100			356,102	1,796	2,313	0	94,879	-263,536	-77,302	-1,203,877
2019									333,362	600	786	0		-334,148	-90,320	-1,294,196
2020									326,860	600	799	0		-327,659	-81,612	-1,375,809
2021									320,277	1,796	2,433	0		-322,710	-74,069	-1,449,878
2022									313,616	600	827	0		-314,442	-66,505	-1,516,383
2023						1,092,732			458,276	600	841	0	47,770	-411,346	-80,170	-1,596,553
2024									437,022	1,796	2,559	0		-439,581	-78,947	-1,675,499
2025									427,920	600	869	0		-428,789	-70,962	-1,746,462
2026									418,714	600	884	0		-419,598	-63,989	-1,810,451
2027									409,408	8,036	12,043	0		-421,452	-59,226	-1,869,677
2028									400,008	600	914	0		-400,922	-51,918	-1,921,595
2029									390,516	600	930	0		-391,446	-46,711	-1,968,306
2030									380,936	1,796	2,831	0		-383,767	-42,199	-2,010,505
2031									371,272	600	962	0		-372,234	-37,717	-2,048,222
2032									361,527	600	978	0		-362,506	-33,848	-2,082,070
2033									351,705	1,796	2,978	0		-354,683	-30,517	-2,112,588
2034									341,808	600	1,012	0		-342,819	-27,181	-2,139,768
2035									331,839	600	1,029	0		-332,868	-24,320	-2,164,088
2036									321,802	1,796	3,133	0		-324,934	-21,876	-2,185,964
2037									311,698	600	1,064	0		-312,762	-19,404	-2,205,368
2038									301,532	600	1,082	0		-302,614	-17,300	-2,222,668
2039									291,304	8,036	14,743	0		-306,047	-16,123	-2,238,791
2040									281,018	600	1,120	0		-282,138	-13,696	-2,252,487
2041									270,676	600	1,139	0		-271,815	-12,159	-2,264,646
2042									201,430	1,796	3,466	0		-204,896	-8,446	-2,273,092

Project Title: **Rebuild Transmission Lines**

Location: **Various**

Classification: **Transmission**

Project Cost: **$2,315,000**

This project consists of a number of items as noted.

(a) Rebuild 3L (Petty Harbour – Goulds)

Cost: $364,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on a 4.7km section of 3L.

Operating Experience: 3L was built in 1930. It is a radial line servicing 400 customers in the Petty Harbour area. It also provides a tie between the Petty Harbour hydro plant and the main electrical grid. There have been several unplanned outages on this line during the past 4 or 5 years resulting from deteriorated line components. In 2000, $10,000 was spent correcting deficiencies identified during that year's inspection. In 2003, one kilometre of line was rebuilt due to deterioration and substandard ground clearances at a cost of $139,000.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware on a 4.7 km section of 3L. Upgrading of this section of line is necessary to ensure continuity of service to customers in the Petty Harbour area as well as provide the hydro plant with a secure connection to the main grid.

(b) Rebuild 16L (Pepperell – King's Bridge)

Cost: $197,000

Description: This project consists of increasing the conductor size and the replacement of deteriorated poles and hardware on 2.0 km of transmission line 16L.

Operating Experience: 16L was built in 1950. The conductor on this line is a small size relative to that in use today which creates a restriction in the power flow and an outage to Virginia Waters Substation when 58L and 34L are out of service. See Volume III, Transmission, Appendix 1, Attachment A. From a structural perspective the most recent work was in December 1994, and involved the replacement of several poles which collapsed during a sleet storm.

Justification: The small conductor used on this transmission line limits its ability to carry current. Upgrading this line will strengthen the east end transmission loop which will increase reliability of the transmission grid.

(c) Rebuild 38L (Seal Cove – Duffs)

Cost: $231,000

Description: This project consists of increasing the conductor size and the replacement of deteriorated poles and hardware on a 2.8 km section of transmission line 38L.

Operating Experience: This line was built in 1961. Poles, crossarms, insulators and hardware are showing deterioration on a 2.8 km section of this transmission line. The small size conductor on this section of the line has on several occasions limited the line’s ability to carry available power between Duffs and Hardwood Substations. See Volume III, Transmission, Appendix 1, Attachment A. In 2001, $8,000 was spent correcting miscellaneous deficiencies.

Justification: This line is a tie between Hydro’s Holyrood Generating Plant and the substations in the CBS area (SCV, KEL and CHA). By upgrading this 2.8 km section of line and increasing the conductor size this project will increase reliability not just to the CBS area but also to St. John’s in the event of a loss of infeed to Hardwoods Substation.

(d) Replace deteriorated poles and hardware 116L (Hare Bay – Wesleyville)

Cost: $130,000

Description: This project consists of the replacement of approximately 25 deteriorated poles and hardware on transmission line 116L.

Operating Experience: 116L was built in 1973. It is a radial line servicing the Bonavista Bay North area. Based on inspections, replacement of deteriorated material is completed as necessary. In 2000, $151,000 was spent on replacement of deteriorated poles, crossarms, insulators and hardware. In 2002, a further $19,000 was spent.

Justification: Inspections have identified deteriorated poles and hardware that require replacement in order to maintain the integrity of the line and reliability of service to customers in the Bonavista North area.

(e) Replace defective insulators and associated hardware on transmission line 123L (Clarenville to Catalina)

Cost: $112,000

Description: This project consists of the replacement of approximately 1,200 defective insulators and associated hardware on transmission line 123L.

Operating Experience: 123L was built in 1976. It is a radial line servicing the Bonavista Peninsula. Inspections have identified defective insulators and deteriorated hardware on this line. Based on inspections, $3,000, $229,000 and $61,000 were spent in 2000, 2002 and 2003 respectively on the replacement of deteriorated hardware.

Justification: The type of insulator being replaced has a manufacturing defect that leads to mechanical failure. Replacement is necessary in order to maintain integrity of the line and reliability of service to customers on the Bonavista Peninsula.

(f) Replace deteriorated poles and hardware on transmission line 124L (Clarenville to Gambo)

Cost: $96,000

Description: This project consists of the replacement of approximately 16 deteriorated poles, structures and hardware on transmission line 124L.

Operating Experience: 124L was built in 1964. Based on inspections, $16,000, $40,000 and $26,000 were spent in 2000, 2001 and 2002 respectively on the replacement of deteriorated line hardware.

Justification: Inspections have identified deteriorated poles, structures and hardware that require replacement in order to maintain the integrity of this line.

(g) Replace defective insulators and associated hardware on transmission line 132L (Grand Falls to Bishop's Falls)

Cost: $66,000

Description: This project consists of the replacement of approximately 1,100 insulators and associated hardware on 52 structures of transmission line 132L.

Operating Experience: 132L was built in 1976. Based on inspections, replacement of excessively worn or broken parts is completed as necessary. In 2000, $2,000 was spent and in 2002, $1,000 was spent. There have been several outages over the past few years caused by failed insulators.

Justification: The type of insulator being replaced has a manufacturing defect that leads to mechanical failure. Replacement is necessary in order to maintain the integrity of the line, and reliability of service to customers in the Bishop's Falls area.

(h) Rebuild 5.1 km of 403L (St. Georges – Lookout Brook)

Cost: $380,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on a 5.1 km section as well as selective pole and hardware replacement on a 4 km section of transmission line 403L.

Operating Experience: 403L was built in 1958. It is a radial line servicing customers in the Robinson's/Flat Bay area. It also provides a tie between the Lookout Brook hydro plant and the main electrical grid. In 2001, 11.6 km of this line was replaced because of significant deterioration of its poles and hardware. Another 5.1 km of this line is in a similar deteriorated condition.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware. Extensive upgrading is necessary to ensure continuity of service to customers in the area as well as to provide the hydro plant with a secure connection to the main grid.

(i) Projects < $50,000

Cost: $739,000

Description: There are approximately 50 other lines that require replacement of deteriorated items.

Operating Experience: Annual inspections have identified deteriorated items that need to be replaced.

Justification: This project is necessary to replace poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections in order to ensure that such lines provide reliable service to customers and are safe for both the public and line workers.

Transmission
Appendix 1
Attachment A

Newfoundland Power Inc.
St. John’s Transmission
Ampacity Review

Prepared On:
July 17, 2003

Table of Contents

Introduction

This review was initiated as a result of recent events associated with the loss of the Oxen Pond (OXP) - Hydro infeed to the St. John's electrical system. While the widespread customer outages were caused by equipment failure in the Hydro portion of the OXP substation, there were difficulties encountered in switching the loads to the Hardwoods (HWD) substation. Among the limitations that were recognized in the process was the inability of some of the local 66 kV transmission lines to carry these loads without overloading due to exceeding the ampacity ratings of those transmission line conductors.

Many lines in the St. John's area 66 kV transmission system are limited in the load that can be carried due to conductor thermal ampacity ratings. This is not typical of the majority of the Newfoundland Power transmission system where low voltage conditions tend to be the limiting factor. The lines in the St. John's transmission system that are ampacity limited tend to be relatively short lines carrying relatively large loads compared to the transmission lines elsewhere in the Newfoundland Power electrical system.

Comparing forecasted substation loads and existing St. John's transmission line ampacities indicates that existing St. John's transmission lines will not be overloaded under normal peak loading conditions for the foreseeable future. This review focuses on contingency situations, where one or more transmission lines, or Hydro infeed transformers, are out of service. In such circumstances some St. John's transmission lines will overload by exceeding ampacity ratings.

While this review was initiated by the recent events at OXP, the review analyses other contingencies. Contingencies can be both unplanned and planned. For example the OXP equipment failure was unplanned. An example of a planned situation would be Hydro requiring portions of the OXP or HWD infeed substations in St. John's to be removed from service for preventative maintenance purposes.

The result of this review is a recommendation to upgrade the ampacity of certain 66 kV transmission lines in the St. John's area. Table 1 (Page 10) identifies the proposed transmission lines, the proposed year for upgrade and the estimated upgrade cost.

Existing System

The St. John's 66 kV transmission system is composed of the transmission lines identified in Figure 1 (Page 14). A unique line number identifies the lines and each line connects two or more substations. (e.g. transmission line 51L connects KEL [Kelligrews] substation to CHA [Chamberlains] substation) The ampacity limitation of each line in MVA is indicated below the line number. This ampacity limitation is based on the smallest conductor on the transmission line. A transmission line is usually constructed entirely of one conductor type when it is initially built. However, as portions of a transmission line are rebuilt over time, the construction standards at the time dictate conductors that may not be the same as the rest of that transmission line. Table 2 (Page 11) shows the various conductors on each transmission line in the St. John's area.

The ampacity limitations (MVA) in Figure 1 on page 14 show two numbers for each transmission line. The smaller number is reflective of summer conditions, and the larger number of winter or peak load conditions. The summer condition is based on an ambient temperature of 25 °C, wind of 0.61 m/sec (2 feet per sec) and a maximum conductor temperature of 75 °C. The winter condition is based on an ambient temperature of 0°C, wind of 0.61 m/sec (2 feet per sec) and a maximum conductor temperature of 75°C. Protective relaying and company practices would ensure that conductors are not operated in such a way as to exceed these limitations.

Contingency Situations

Under normal peak load conditions, with all facilities in service, ampacity limitations of the St. John's 66 kV transmission system are not exceeded for the near future (minimum of 5 years). This review therefore focuses on contingency situations. These are situations under which one or more components of the transmission or substation system are out of service. Under some of these contingencies the system can continue to supply service through alternate routes with loadings that may exceed peak load conditions for that route. However, the issue addressed in this review, is that contingency loading may exceed the ampacity limitations of certain transmission lines.

The contingencies considered as part of this review are in two categories. The first is 'single contingency outages'. This means that substations that normally have two sources of supply would continue to be supplied when one of those sources of supply is removed. Typical of this is a substation that is supplied via two transmission lines. The removal of one transmission line could be either an unscheduled outage or scheduled outage to perform maintenance. In the St. John's area there are a number of substations that are supplied via two or more transmission lines. These provide single contingency outage backup. A major portion of this analysis reviews such contingencies and proposes upgrading transmission lines when overloads occur under such single contingency circumstances. When one transmission line is removed, the substation can still be supplied via the other line within acceptable voltage limits and without other components of the electrical system becoming overloaded under peak load conditions.

The second general category is loss of 230 kV infeed supply to either of Hydro's substations. While the loss of one infeed transformer at either substation is considered a single contingency event, the loss of all transformers or a bus fault is considered a multiple contingency event. Power system planning criteria does not provide for no loss of load under multiple contingency events. It would not be reasonable to provide the amount of capacity that would be required at one Hydro infeed substation such that the loss of the other substation could be accommodated under peak load conditions. However, it is prudent that such a situation be accommodated at some load level. It was such a condition that initiated this review of transmission line loadings.

This review examines the transmission loadings that occur on loss of infeed supply to one Hydro substation under reduced loading conditions. The review examines the conditions where the infeed transformers at the remaining infeed substation are loaded to capacity and establishes which 66 kV transmission lines are overloaded in such circumstances. Where such lines are overloaded it proposes upgrading the lines for increased capacity. As part of this analysis, load flow simulations were undertaken using the 2004 forecasted peaks indicated in Table 3 (Page 13). The results of these load flows are contained in Appendix A. The flows indicated on the charts are in MW and MVAR, and should be converted to MVA for comparison with ampacity expressed in MVA.

Appendix A contains the 2004 load flows used to identify current problem areas within the St. John's area transmission system. Appendix B contains the 2008 load flows used to confirm the validity of upgrading transmission lines for ampacity purposes within the 2004 – 2008 time period. The base case system and associated load flow for this analysis is indicated in load flow 1 of Appendix A.

The following examine various contingency situations and establish which transmission lines should be upgraded for ampacity purposes.

<u>OXP-RRD-KBR-PEP-VIR-OXP Loop</u>

This is composed of a simple loop with dual supplies from the OXP substation to each of the Ridge Road (RRD) and Virginia Waters (VIR) substations. These dual lines are on separate structures with the exception of a section of the OXP-VIR double circuit where the lines are on the same structure. This loop is highlighted in Figure 2.

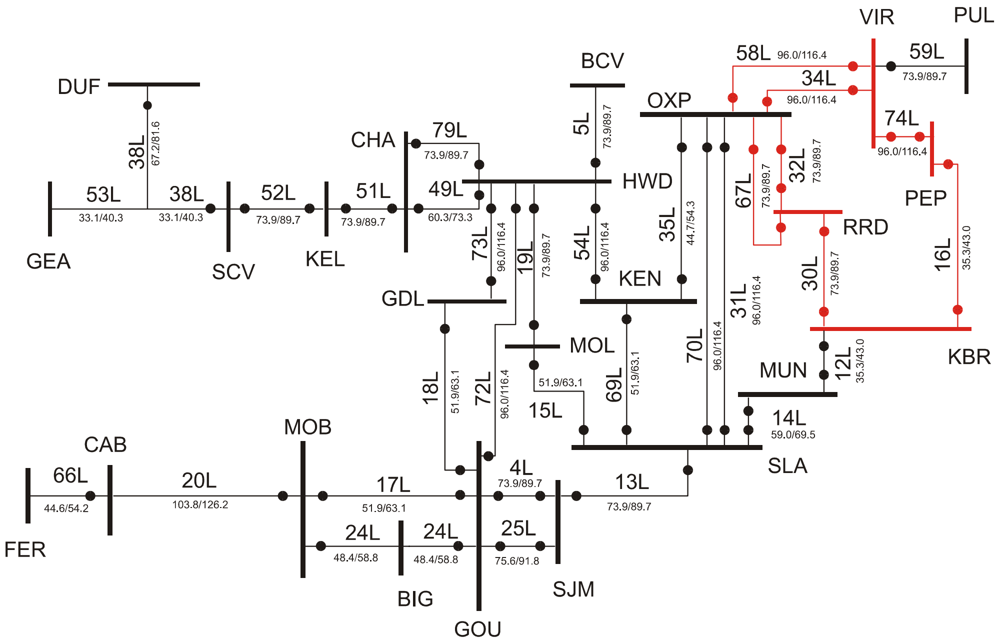


Figure 2: OXP-RRD-KBR-PEP-VIR-OXP Loop.

The 2004 peak substation loads supplied via this loop, including the Newfoundland Power substations noted above and Pulpit Rock (PUL) substation, total 171.7 MVA. Contingency analysis does not normally evaluate the loss of two lines at the same time. However in this case where a portion of the dual supply lines is on the same structures, there is concern regarding the ability to perform preventative maintenance on the double circuit OXP-VIR line without removing customers from service. For example, the ability to perform maintenance on OXP-VIR (58L and 34L) even under a typical summer daily conditions (50% of peak) without removing some customers from service would not be possible without overloading 16L transmission line from PEP-VIR. The summer load typical daily peak is considered to be 50% of annual peak. For the substations serviced from 16L, the summer peak load totals 45.7 MVA {(PEP+VIR+PUL)*50%} compared to summer ampacity of 16L at 35.3 MVA. Such maintenance would not be possible in winter months without removing customers from service. It is recommended that 16L transmission line ampacity be increased to 116.4 MVA in 2004. This involves changing the conductor from 1/0 copper to 715.5 aluminium. In order to further improve the capacity of this loop system, it is recommended that 30L be upgraded to 116.4 MVA when the line is rebuilt in 2007 due to deteriorated poles and hardware. This has been identified as part of the Company's annual transmission inspection process.

Two further transmission lines that are on the same structures for part of their length are 30L (KBR-RRD) and 16L (KBR-PEP). On contingency loss of these lines during peak conditions, the King's Bridge load can be accommodated through 12L (KBR-MUN).

The overloads of 16L under 2004 peak load conditions are indicated in load flows 2, 3 and 6 of Appendix A. An overload of 30L is indicated in load flow 3.

OXP-SLA Dual Supply

The dual transmission supply from OXP-SLA (31L and 70L) has both lines on the same structure for a significant portion of its length. This dual supply is highlighted in Figure 3.

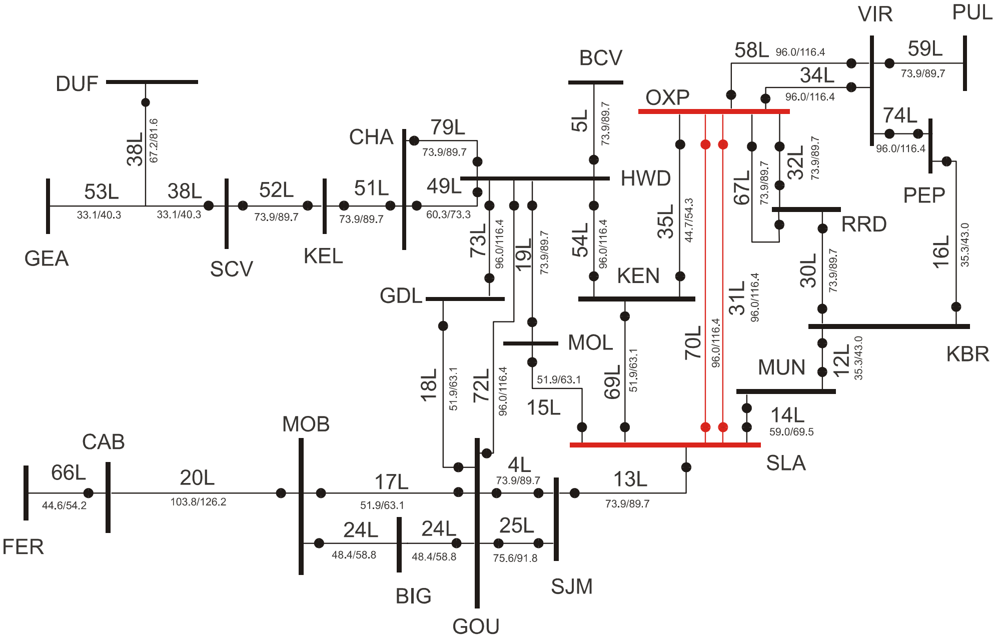


Figure 3: OXP-SLA Dual Supply.

Simultaneous loss of both lines, as indicated in load flow 7, results in 12L becoming overloaded. As shown in load flow 8, opening 35L will eliminate this overload. In addition, SLA-MUN (14L) is also on the same structures for part of its length. An outage of this line at the same time causes no transmission ampacity problems.

SLA- MUN-KBR Alternate Supply to MUN

This is a dual supply to Memorial University (MUN) from two adjacent loop systems. The dual supply to MUN is highlighted in Figure 4.

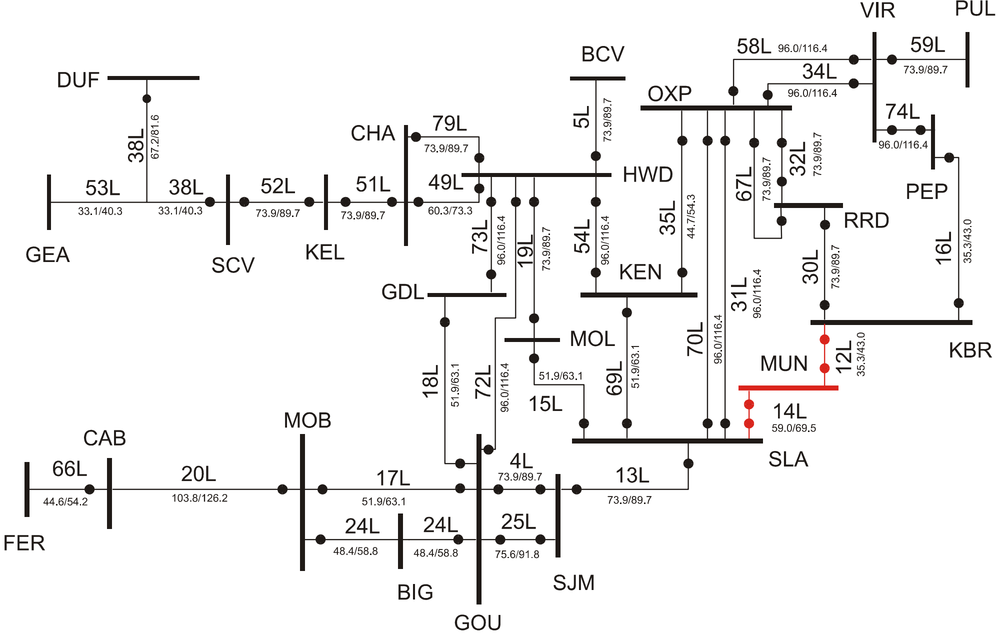


Figure 4: SLA-MUN-KBR Alternate Supply to MUN.

Both 12L and 14L have sections that are composed of underground cable rated 59/69.5 MVA. While the SLA-MUN-KBR supply can provide support to other substations under some outage circumstances; its ampacity limitation would not be exceeded in supplying only the MUN peak load (16 MVA).

Load flows 5 and 7 indicate cases where 12L is overloaded under contingency conditions. It is recommended that 12L be upgraded such that the cable section is the limiting ampacity. The Company's annual transmission inspection process has identified that 12L should be rebuilt in 2008, at which time the conductor should also be upgraded.

DUF-SCV-KEL-CHA-HWD Dual Infeed System

Within this system a portion of 38L has an ampacity of 33.1/40.3 MVA. The 50 MVA of transformer capacity at Holyrood 230/66 kV also limits this dual infeed system from the Holyrood supply point. This dual infeed system is highlighted in Figure 5.

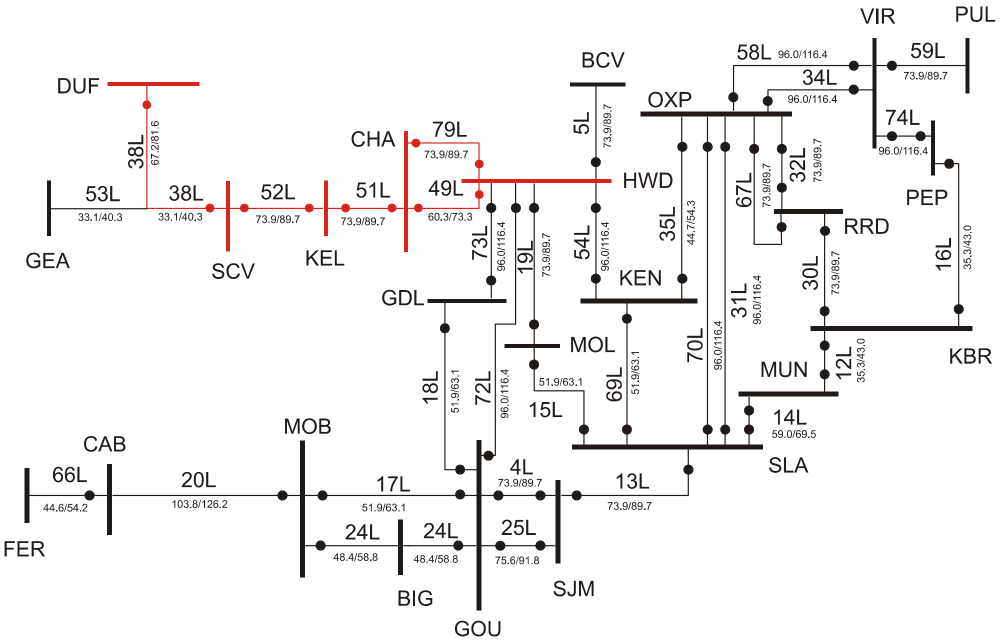


Figure 5: DUF-SCV-KEL-CHA-HWD Dual Infeed System.

Concerns with this system are the contingencies that involve the loss of 230/66 kV transformer infeed capacity at HWD and OXP. Under such circumstances it is necessary to reduce the load on the HWD and OXP transformers to within their rated capacities. Opening the lines between CHA and HWD would enable this entire Conception Bay South load to be supplied via the DUF infeed transformers. The 2004 peak loads at SCV, KEL and CHA total 53.8 MVA. This exceeds the 40.3 MVA of 38L but approximates the transformer capacity at the DUF infeed. Under low load conditions, this system can supply load into the HWD area as well. It is recommended that the ampacity of 38L be increased to 116.4 MVA through the installation of 715.5 MCM conductor.

Of special concern is the circumstance immediately following loss of infeed supply at HWD or OXP. If, as a result of loss of infeed supply to one of HWD or OXP, the protective relaying for 38L trips the line due to overload, then the result would further exacerbate infeed overloads at HWD or OXP. These overloads might then contribute to further overloads or St. John's system collapse. Improving the ampacity of 38L would mitigate the potential for this problem occurring.

Load flow 9 indicates that 38L is overloaded under winter peak conditions with both HWD-CHA lines (49L and 79L) out of service. Also load flows 24, 27 and 28 show examples where an upgraded 38L is important when there are transformer infeed outages at OXP and HWD.

It is recommended that 38L be upgraded in 2004 such that this system is not limited by the ampacity rating of the transmission line.

HWD-GDL-GOU-SJM-SLA-OXP Dual Infeed System

This is a valuable dual infeed system on loss of HWD or OXP infeed supply. This dual infeed system is highlighted in Figure 6.

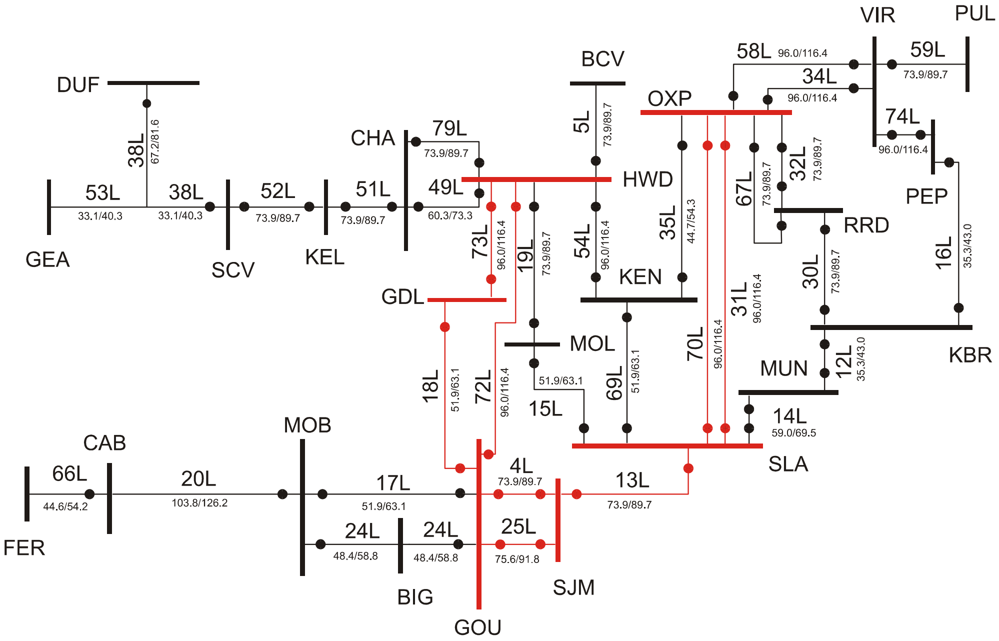


Figure 6: HWD-GDL-GOU-SJM-SLA-OXP Dual Infeed System.

Given the loads and the ampacity limitations, it is not considered necessary to upgrade the lines within this loop for ampacity purposes.

There are two transmission lines on the same structures for a portion of their length after they exit St. John’s Main SJM substation, SJM-SLA (13L) and SJM-GOU (4L). Loss of these two lines is adequately carried on peak by the remaining SJM-GOU line (25L) as indicated in load flow 29.

HWD-MOL-SLA-KEN-OXP Dual Infeed System

This is a valuable dual infeed system on loss of HWD or OXP infeed supply. This dual infeed system is highlighted in Figure 7.

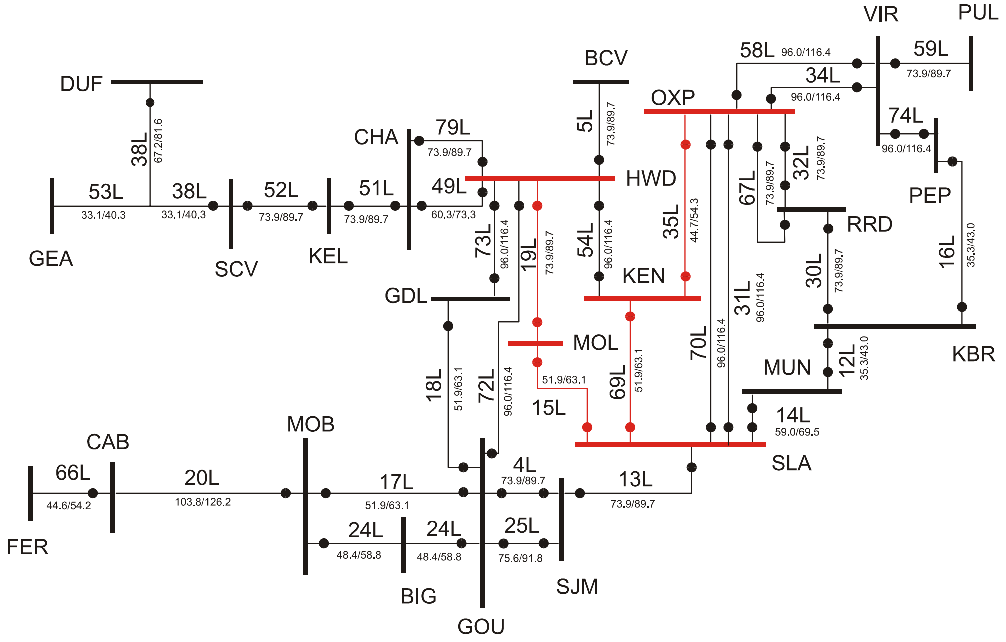


Figure 7: HWD-MOL-SLA-KEN-OXP Dual Infeed System.

The ampacity of 69L and 19L are of concern under these conditions, especially under conditions where summer ampacity conditions may apply. Load flows 14, 15, 16, 17 and 24 are examples where an upgrade to 69L and19L would be of value.

As part of the Company's transmission inspection process, 69L has been scheduled for rebuilding in 2007. It is recommended that 69L be upgraded for ampacity purposes during that time.

Loss of one of Hydro's largest transformers at the infeed point has been an accepted contingency to be met under peak load conditions. Load flow 10 indicates the power flows under peak loads for loss of a 125 MVA 230/66 kV transformer at OXP. There are no transmission overloads as a result, but the remaining infeed transformers at OXP become overloaded. By using the 50 MW gas turbine at HWD and opening selected lines in the 66 kV system, the overload on the OXP transformers can be removed with no overloads on the 66 kV transmission system, as indicated in load flow 13.

<u>All OXP 230/66 kV Transformers Out Of Service</u>

While the loss of all OXP 230/66 kV transformers constitutes an extreme contingency, it has happened a number of times because the transformer protection clears the 230 kV incoming circuits and the 66 kV bus. One would not expect the system to be able to supply all customers on peak under such circumstances. However, there is an expectation that, at some load level, service would be maintained to all customers in such a contingency.

There is also the circumstance where Hydro requires an outage to its portion of the OXP substation for preventative maintenance purposes. This is normally done during lighter load conditions. This condition has the same system configuration as loss of all infeed transformers at the substation.

At 65% of peak loads, all customers can be supplied by HWD with the HWD 50 MW GT in service and no infeed transformers or transmission lines overload at HWD.

At 80% of peak loads with the HWD 50 MW GT in service, there are transformer overloads at HWD that cannot be reduced below overload, as indicated in load flow 17b.

Care must be taken when the system is not under winter peak conditions and when ambient temperatures are higher, that appropriate transmission line ratings be used. This may be the case when the complete 230/66 kV supply is lost at either the OXP or HWD substations or especially under summer preventative maintenance conditions.

One HWD 125 MVA Transformer Out Of Service

Load flow 18 shows the power flows under peak loads for loss of a 125 MVA 230/66 kV transformer at HWD. While there are no transmission overloads as a result, remaining infeed transformers at HWD become overloaded. The transformer overloads are removed by using the 50 MW gas turbine at HWD as seen in load flow 20.

All HWD 230/66 kV Transformers Out Of Service

As in the OXP case, the loss of all HWD 230/66 kV transformers constitutes an extreme contingency. One would not expect the system to be able to supply all customers on peak under such circumstances. However, there is an expectation that, at some load level, service would be maintained to all customers in such unplanned contingencies and for scheduled maintenance outages of the Hydro infeed system at HWD.

At 60% of peak loads, all customers can be supplied via the existing system, but 38L overloads as indicated in load flow 23.

At 80% of peak loads with the HWD 50 MW GT in service, there are no transformer overloads. However 38L overloads as indicated in load flow 26.

Summary of Recommendations

Table 1 indicates a proposed upgrading of transmission lines within the St. John’s area transmission system for ampacity purposes.

Table 1
Proposed St. John's Area Transmission Upgrades For Ampacity Purposes

Transmission Line	Existing Ampacity (MVA)	Upgrade Length (Km)	Proposed Ampacity	Proposed Year	Estimated Cost
16L - Pepperell to King's Bridge	35.3 / 43.0	1.98	96 / 116.4	2004	$197,000
38L - Golden Eagle Tap to Seal Cove	33.0 / 40.3	2.74	96 / 116.4	2004	$231,000
30L – Ridge Road to King's Bridge	73.9 / 89.7	2.91	96 / 116.4	2007	$340,000
69L – Kenmount to Stamp's Lane	51.9 / 63.1	3.41	96 / 116.4	2007	$269,000
12L – Memorial to King's Bridge	35.3 / 43.0	2.17	59/69.5	2008	$240,000

Table 2
Transmission Line Conductors

LINE ID	FROM	TO	LENGTH	VOLT	EQUIV. SPC.	CONDUCTOR		AMPACITY RATING	
			(km)	(kV)	(m)	SIZE	TYPE	MVA @ 25C	MVA @ 0C
3 L	GOULDS	PETTY HARBOUR	5.63	33	1.219	1/0	CU	17.6	21.5
4 L	GOULDS	POINT A	8.85	66	1.402	477	ASC	73.9	89.7
4 L	POINT A	MAIN SUB	0.40	66	0	1000	CBLE	86.3	98.9
5 L	HARDWOODS	BROAD COVE	12.87	66	1.951	477	ASC	73.9	89.7
7 L	BROAD COVE	BELL ISLAND	5.40	12.5	0	250	CBLE	0	9.5
11 L	MOBILE	TORS COVE	4.96	66	1.219	3/0	CU	48.4	58.8
12 L	KING'S BRIDGE	POINT A	2.17	66	1.402	1/0	CU	35.3	43
12 L	POINT A	MEMORIAL	0.97	66	0	350	CBLE	59	69.5
13 L	MAIN SUB	POINT A	0.42	66	0	1000	CBLE	86.3	98.9
13 L	POINT A	STAMP'S LANE	2.64	66	1.402	477	ASC	73.9	89.7
14 L	MEMORIAL	POINT A	1.13	66	0	350	CBLE	59	69.5
14 L	POINT A	STAMP'S LANE	1.13	66	1.402	477	ASC	73.9	89.7
15 L	STAMP'S LANE	POINT A	2.35	66	1.707	477	ASC	73.9	89.7
15 L	POINT A	POINT B	0.37	66	1.707	266.8	ASCR	51.9	63.1
15 L	POINT B	POINT C	0.54	66	1.707	477	ASC	73.9	89.7
15 L	POINT C	MOLLOY'S LANE	0.90	66	2.682	477	ASC	73.9	89.7
16 L	KING'S BRIDGE	PEPPERRELL	1.98	66	1.707	1/0	CU	35.3	43
17 L	GOULDS	MOBILE	28.65	66	3.993	266.8	ASCR	51.9	63.1
18 L	GOULDS	POINT A	4.62	66	1.707	266.8	ASCR	51.9	63.1
18 L	POINT A	GLENDALE	1.13	66	1.615	715.5	ASC	96	116.4
19 L	HARDWOODS	POINT A	8.00	66	1.951	715.5	ASC	96	116.4
19 L	POINT A	POINT B	0.61	66	1.951	477	ASC	73.9	89.7
19 L	POINT B	POINT C	0.47	66	1.951	715.5	ASC	96	116.4
19 L	POINT C	MOLLOY'S LANE	0.92	66	2.682	477	ASC	73.9	89.7
20 L	MOBILE	ROCKY PD PLANT	5.81	66	3.993	266.8	ASCR	51.9	63.1
20 L	ROCKY PD PLANT	HORSE CHOPS TAP	12.25	66	3.993	266.8	ASCR	51.9	63.1
20 L	HORSE CHOPS TAP	CAPE BROYLE	2.06	66	3.993	266.8	ASCR	51.9	63.1
21 L	HORSE CHOPS TAP	HORSE CHOPS	5.73	66	3.993	266.8	ASCR	51.9	63.1
22 L	ROCKY POND PLAN	MORRIS PLANT	5.45	66	2	4/0	AASC	44.6	54.2
23 L	MOBILE	PIERRE'S BROOK	5.47	33	1.219	3/0	CU	24.2	29.4
24 L	GOULDS	BIG POND SUBST.	7.76	66	1.951	3/0	CU	48.4	58.8
24 L	BIG POND SUB.	POINT A	12.87	66	1.951	3/0	CU	48.4	58.8
24 L	POINT A	MOBILE	7.76	66	3.993	266.8	ASCR	51.9	63.1
25 L	GOULDS	MAIN SUB	9.25	66	3.444	477	ASCR	75.6	91.8

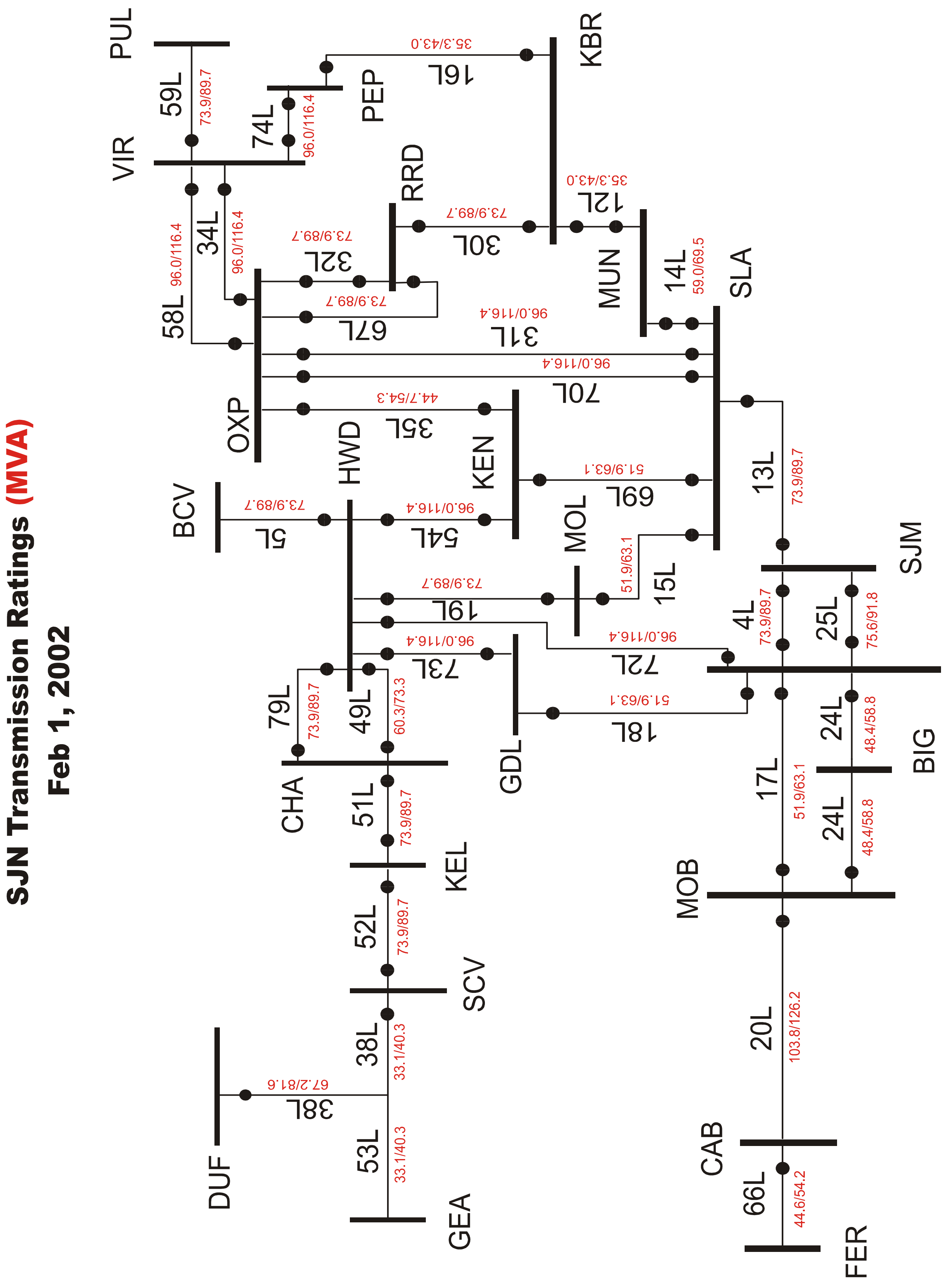
Table 2b
Transmission Line Conductors

LINE ID	FROM	TO	LENGTH	VOLT	EQUIV. SPC.	CONDUCTOR		AMPACITY RATING	
			(km)	(kV)	(m)	SIZE	TYPE	MVA @ 25C	MVA @ 0C
28 L	BROAD COVE	POINT A	0.58	12.5	1.219	3/0	CU	9.2	11.1
28 L	POINT A	BELL ISLAND	6.11	12.5	0	4/0	CBLE	0	7.7
30 L	RIDGE ROAD	KING'S BRIDGE	2.91	66	1.402	477	ASC	73.9	89.7
31 L	OXEN POND	STAMP'S LANE	2.54	66	2.304	715.5	ASC	96	116.4
32 L	OXEN POND	RIDGE ROAD	3.07	66	1.402	477	ASC	73.9	89.7
34 L	OXEN POND	POINT A	2.09	66	2.286	715.5	ASC	96	116.4
34 L	POINT A	POINT B	2.83	66	1.947	715.5	ASC	96	116.4
34 L	POINT B	POINT C	1.53	66	1.951	715.5	ASC	96	116.4
34 L	POINT C	VIRGINIA WATERS	2.83	66	2.286	715.5	ASC	96	116.4
35 L	OXEN POND	POINT A	2.04	66	1.951	477	ASC	73.9	89.7
35 L	POINT A	POINT B	3.39	66	1.707	4/0	ASCR	44.7	54.3
35 L	POINT B	KENMOUNT	1.51	66	1.951	715.5	ASC	96	116.4
38 L	HOLYROOD	GLDEN EAGLE TAP	0.80	66	1.951	397.5	ASCR	67.2	81.6
38 L	GLDEN EAGLE TAP	SEAL COVE	2.74	66	1.951	2/0	ASCR	33.1	40.3
49 L	HARDWOODS	POINT A	2.72	66	1.402	336.4	ASCR	60.3	73.3
49 L	POINT A	CHAMBERLAINS	5.50	66	1.951	477	ASC	73.9	89.7
51 L	CHAMBERLAINS	POINT A	1.54	66	1.92	477	ASC	73.9	89.7
51 L	POINT A	KELLIGREWS	8.61	66	1.951	477	ASC	73.9	89.7
52 L	KELLIGREWS	SEAL COVE	8.22	66	1.951	477	ASC	73.9	89.7
53 L	GLDEN EAGLE TAP	GOLDEN EAGLE	5.95	66	1.951	2/0	ASCR	33.1	40.3
54 L	HARDWOODS	KENMOUNT	8.00	66	1.951	715.5	ASC	96	116.4
58 L	OXEN POND	POINT A	3.84	66	1.951	715.5	ASC	96	116.4
58 L	POINT A	VIRGINIA WATERS	2.85	66	2.682	715.5	ASC	96	116.4
59 L	VIRGINA WATERS	PULPIT ROCK	7.72	66	1.951	477	ASC	73.9	89.7
66 L	CAPE BROYLE	POINT A	7.24	66	4.039	266.8	ASCR	51.9	63.1
66 L	POINT A	FERMEUSE	14.32	66	1.951	4/0	AASC	44.6	54.2
67 L	OXEN POND	POINT A	4.30	66	1.951	715.5	ASC	96	116.4
67 L	POINT A	RIDGE ROAD	0.16	66	1.951	477	ASC	73.9	89.7
69 L	KENMOUNT	POINT A	1.32	66	1.707	715.5	ASC	96	116.4
69 L	POINT A	POINT B	1.98	66	1.707	266.8	ASCR	51.9	63.1
69 L	POINT B	POINT C	0.37	66	1.951	715.5	ASC	96	116.4
69 L	POINT C	STAMPS LANE	0.76	66	1.707	266.8	ASCR	51.9	63.1
70 L	OXEN POND	STAMPS LANE	2.54	66	2.304	715.5	ASC	96	116.4
72 L	HARDWOODS	GOULDS	11.36	66	1.951	715.5	ASC	96	116.4
73 L	HARDWOODS	POINT A	5.58	66	1.951	715.5	ASC	96	116.4
73 L	POINT A	GLENDALE	1.21	66	1.615	715.5	ASC	96	116.4
74 L	VIRGINIA WATERS	POINT A	1.11	66	3.594	715.5	ASC	96	116.4
74 L	POINT A	PEPPERRELL	4.50	66	2.043	715.5	ASC	96	116.4
79 L	HARDWOODS	POINT A	1.50	66	1.951	715.5	ASC	96	116.4
79 L	POINT A	POINT B	5.42	66	1.947	477	ASC	73.9	89.7
79 L	POINT B	CHAMBERLAINS	1.54	66	1.92	477	ASC	73.9	89.7

Table 3
St. John's Area Substation 5-Year Load Forecast
(2003/05/14)

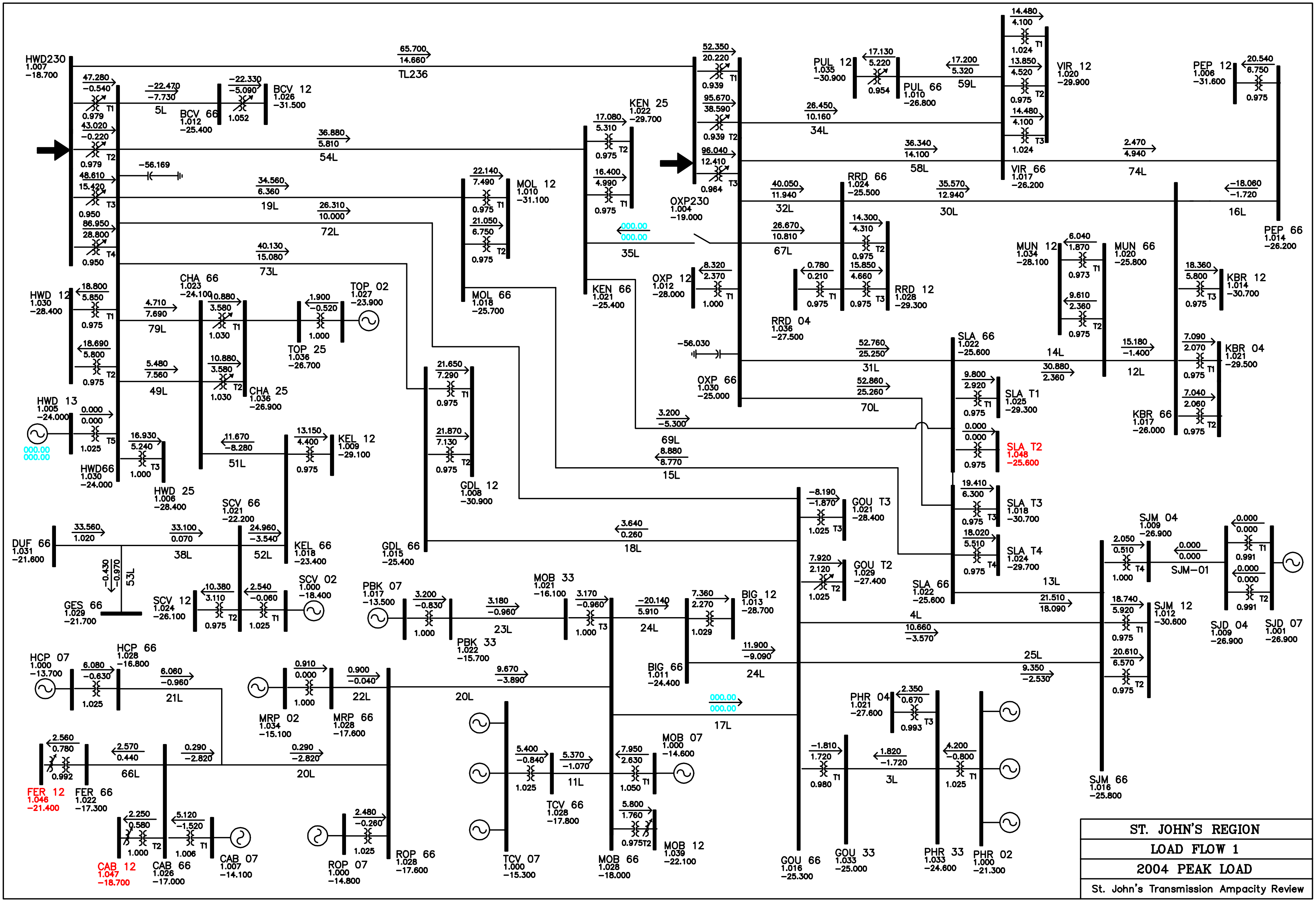
			Operating Voltage	Transformer Capacity - MVA		2002 Peak	Forecasted Undiversified Peak - MVA						Max. XFMR.
	Substation (Notes)	**Des.**	**(kV)**	**Rating**	**Existing**	**MVA**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**Util.**
BIG	Big Pond (13)	T1	12.47	8.4/11.2	11.2	7.5	8.0	8.0	8.0	8.0	9.2	9.3	83%
BCV	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%
CAB	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%
CHA	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%
CHA	Chamberlains	T2	24.94	15/20/25	25.0		13.2	15.7	16.0	16.5	19.0	19.7	79%
FER	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%
GDL	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%
GDL	Glendale	T2	12.47	15/20/25	25.0	22.2	24.9	24.0	23.9	16.7	16.9	17.1	99%
GDL	Glendale	T3	12.47	15/20/25	25.0					16.7	16.9	17.1	68%
GOU	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%
GOU	Goulds	T3	12.47	10/13.3	13.3	8.4	9.0	9.2	9.2	9.4	9.5	9.7	73%
HWD	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%
HWD	Hardwoods	T2	12.47	15/20	20.0	19.6	19.4	19.7	19.7	18.9	19.2	19.5	99%
HWD	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%
HOL	Holyrood 02					1.7	1.8	1.8	1.9	1.9	1.9	1.9	
KEL	Kelligrews (6, 7 & 12)	T1	12.47	11.25/14.95	15.0	13.4	14.6	11.8	12.0	12.3	13.6	14.0	97%
KEN	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%
KEN	Kenmount	T2	24.94	15/20/25	25.0	17.3	19.2	19.4	19.5	19.7	19.9	20.2	81%
KBR	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%
KBR	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%
KBR	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%
MOB	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%
MOL	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%
MOL	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%
OXP	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%
PEP	Pepperrell	T1	12.47	15/20/25	25.0	20.9	22.4	22.6	22.6	22.8	23.1	23.4	94%
PHR	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%
PUL	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%
RRD	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%
RRD	Ridge Road	T2	12.47	15/20	20.0	13.6	15.9	16.3	16.6	17.0	17.5	18.1	91%
RRD	Ridge Road	T3	12.47	15/20	20.0	17.2	17.6	18.1	18.4	18.8	19.4	20.0	100%
SCV	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%**
SJM	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%
SJM	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%
SJM	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%
SLA	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%
SLA	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%
SLA	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%
VIR	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%
VIR	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%
VIR	Virginia Waters	T3	12.47	15/20/25	25.0		16.4	16.9	17.3	17.8	18.5	19.2	77%

Figure 1
St. John's Area Transmission Line Ampacity



APPENDIX A
2004 LOAD FLOW DRAWINGS

Index

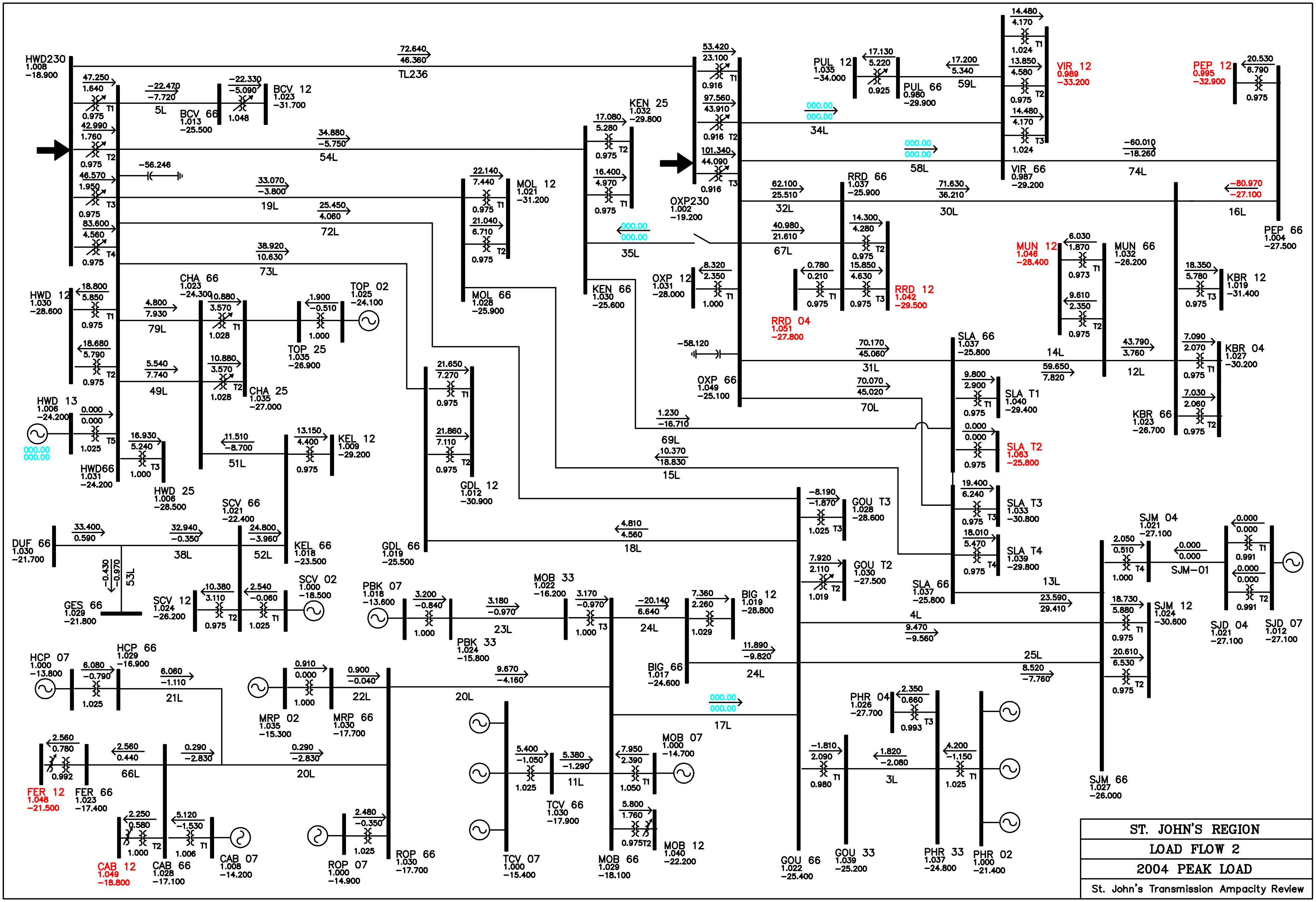


ST. JOHN'S REGION

LOAD FLOW 1

2004 PEAK LOAD

St. John's Transmission Ampacity Review

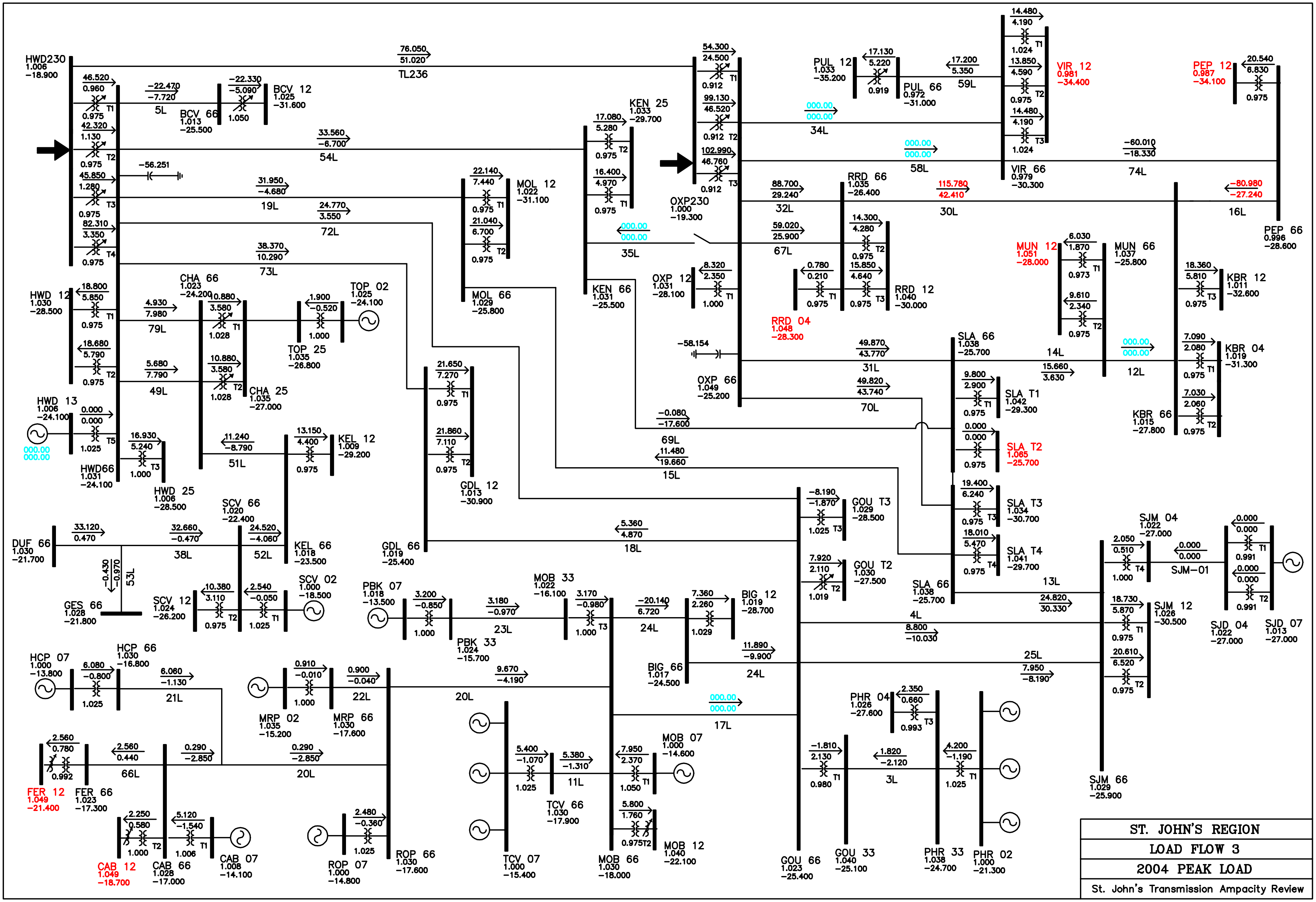


ST. JOHN'S REGION

LOAD FLOW 2

2004 PEAK LOAD

St. John's Transmission Ampacity Review

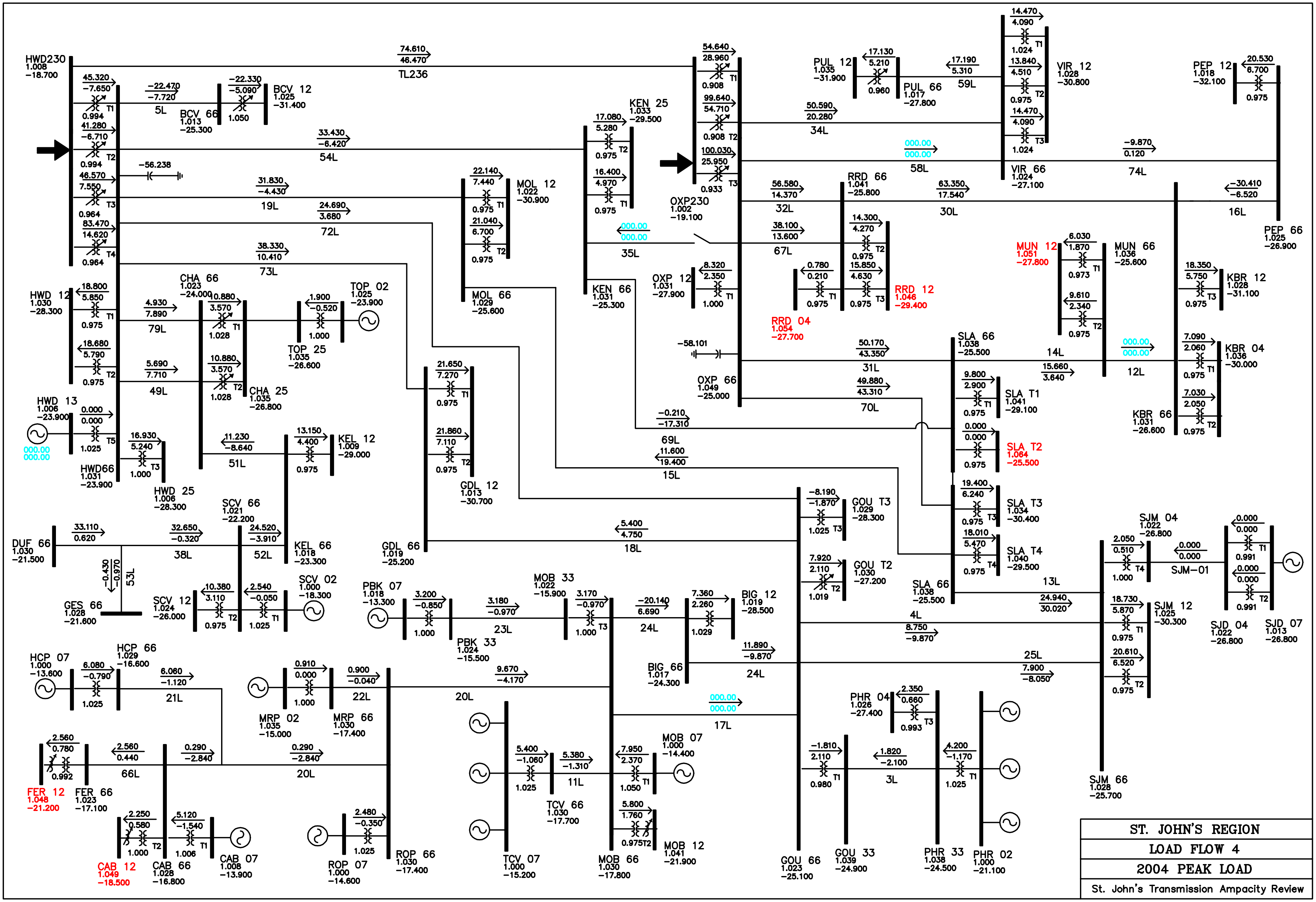


ST. JOHN'S REGION

LOAD FLOW 3

2004 PEAK LOAD

St. John's Transmission Ampacity Review

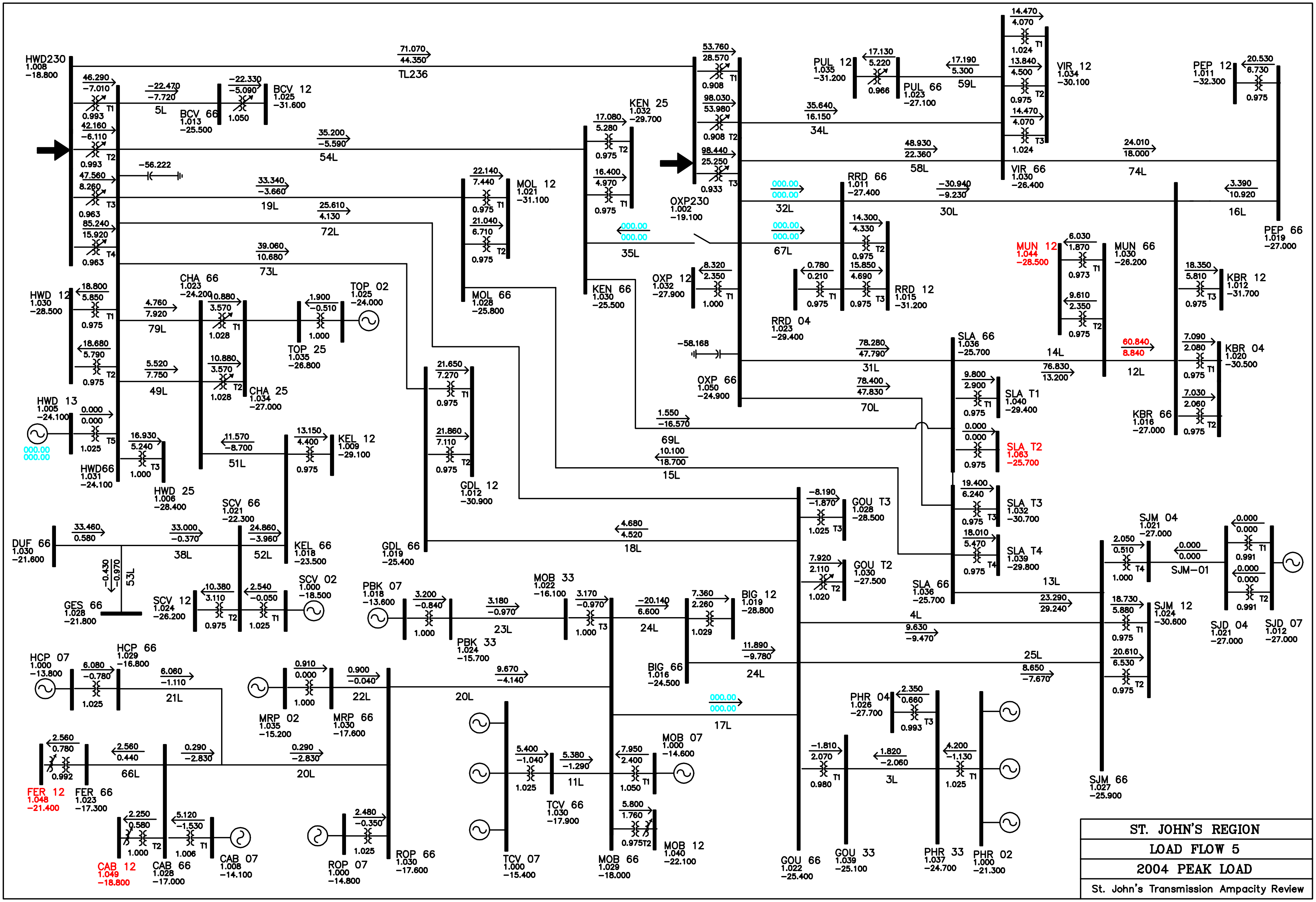


ST. JOHN'S REGION

LOAD FLOW 4

2004 PEAK LOAD

St. John's Transmission Ampacity Review

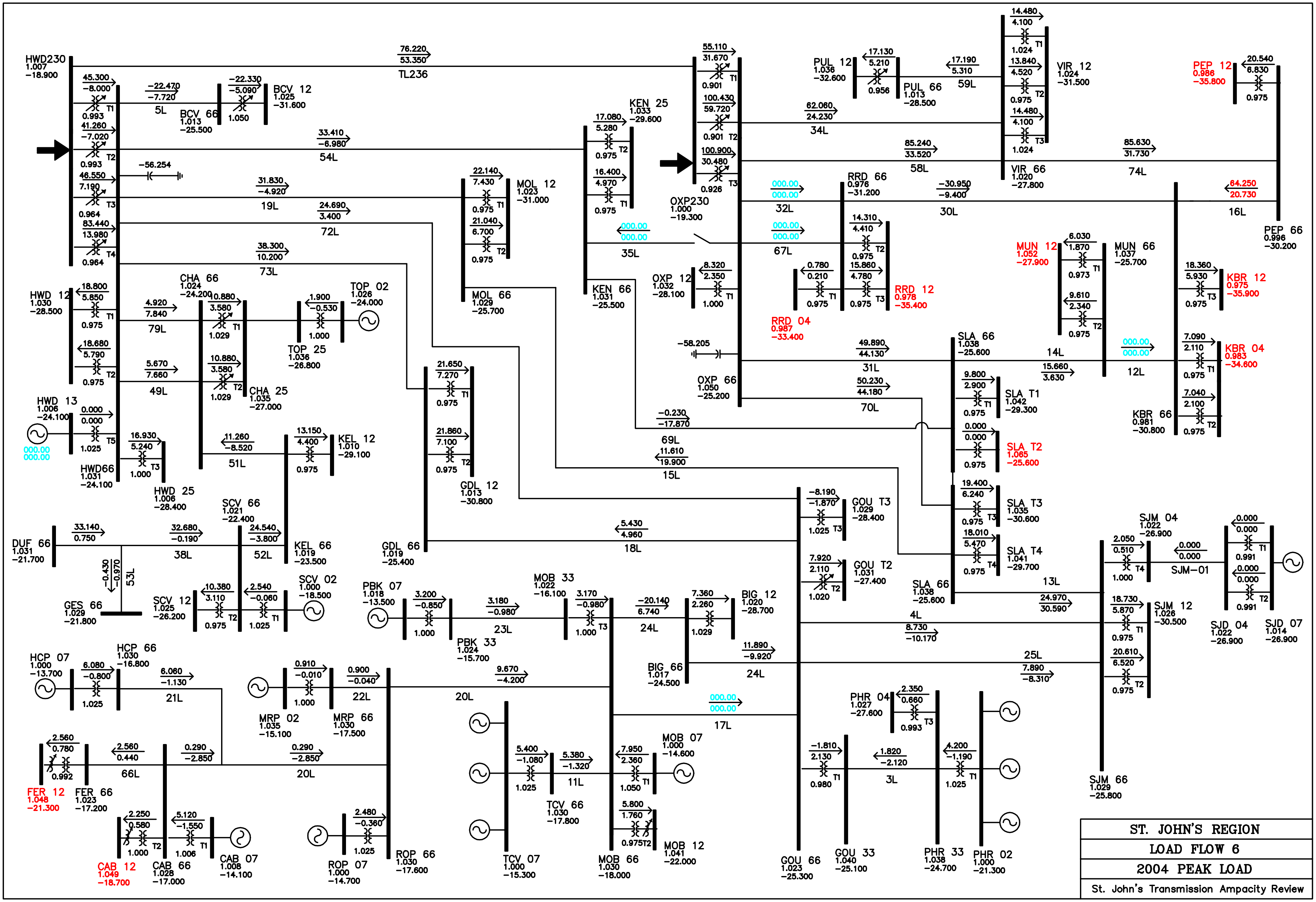


ST. JOHN'S REGION

LOAD FLOW 5

2004 PEAK LOAD

St. John's Transmission Ampacity Review

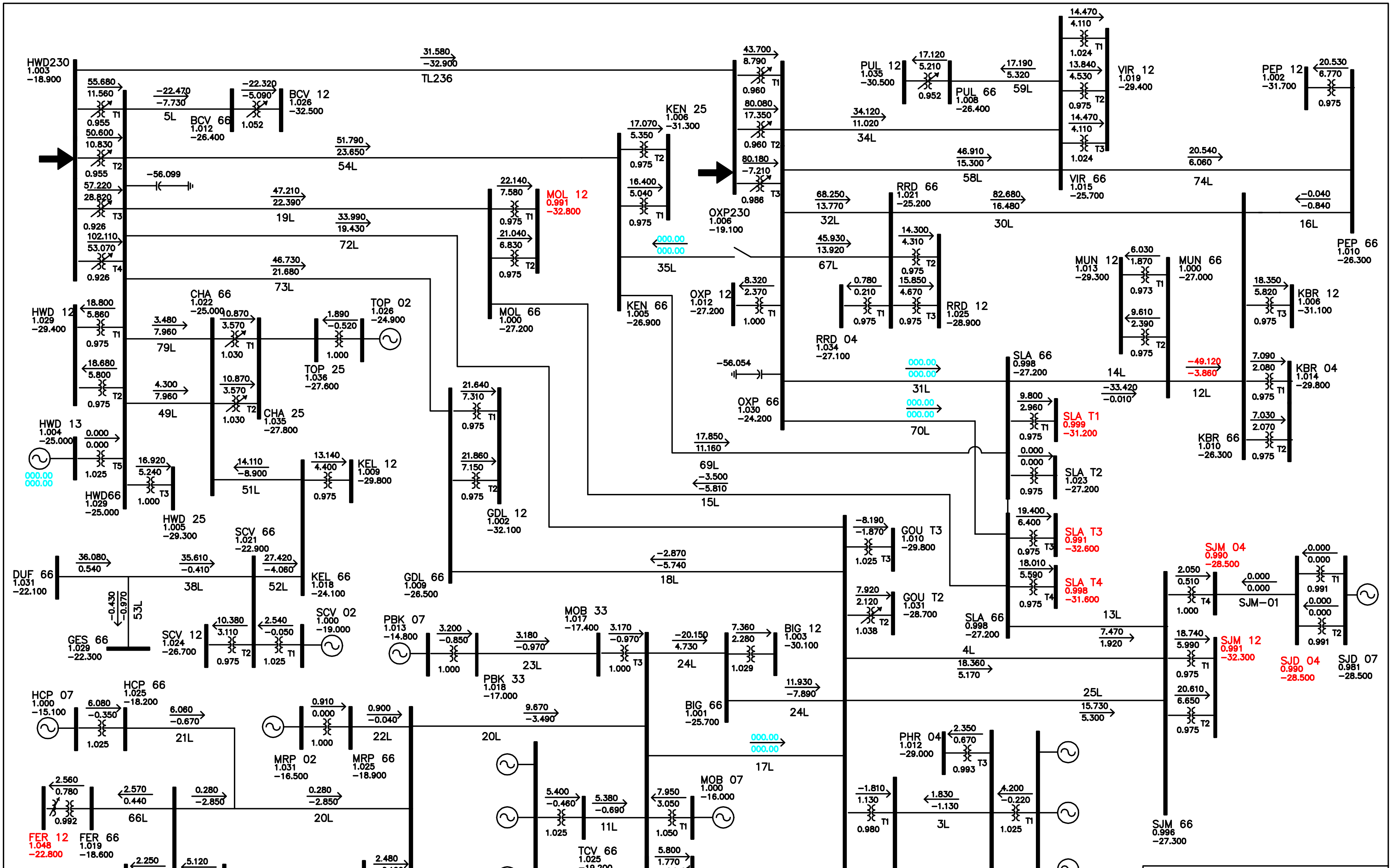


ST. JOHN'S REGION

LOAD FLOW 6

2004 PEAK LOAD

St. John's Transmission Ampacity Review

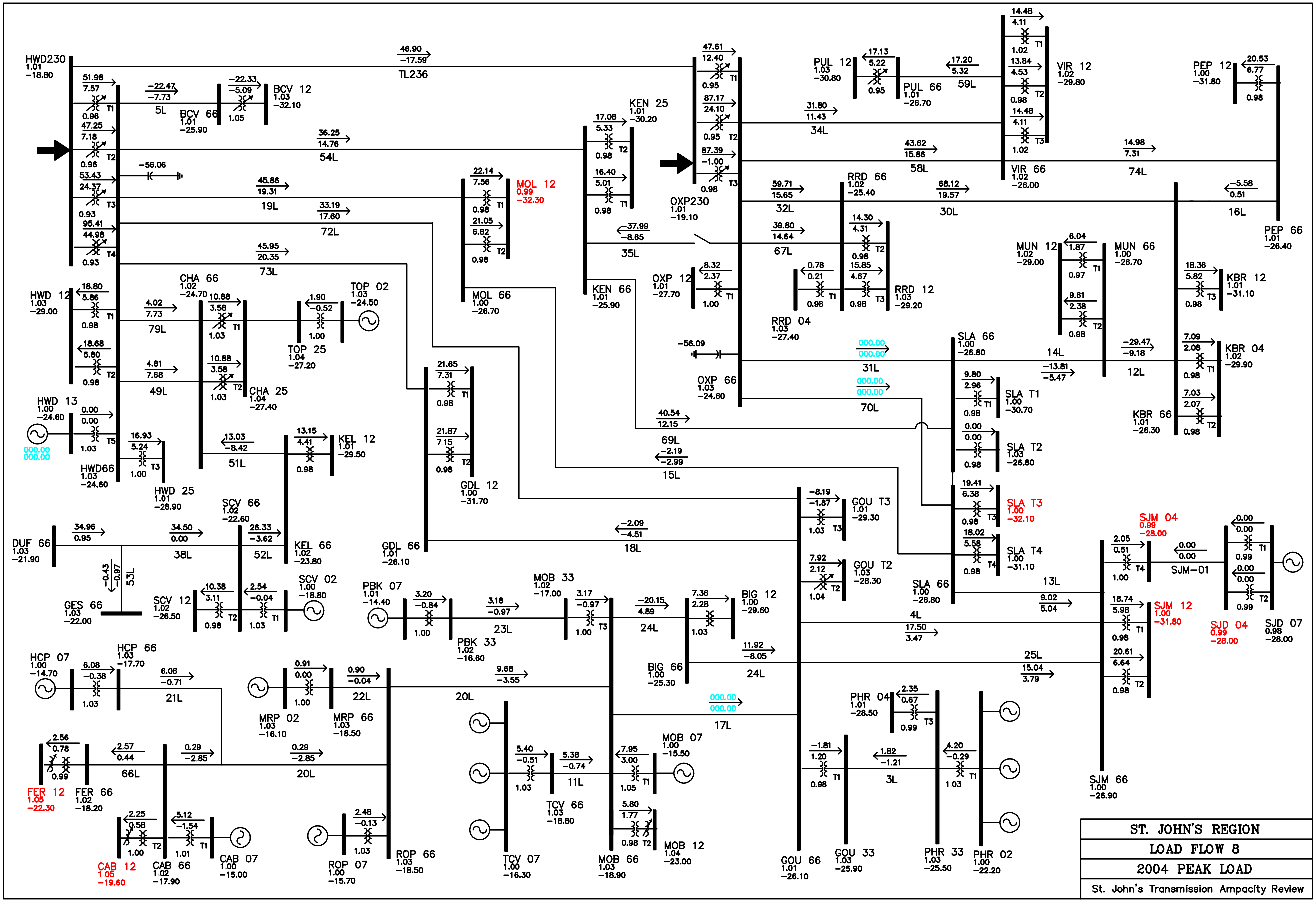


ST. JOHN'S REGION

LOAD FLOW 7

2004 PEAK LOAD

St. John's Transmission Ampacity Review

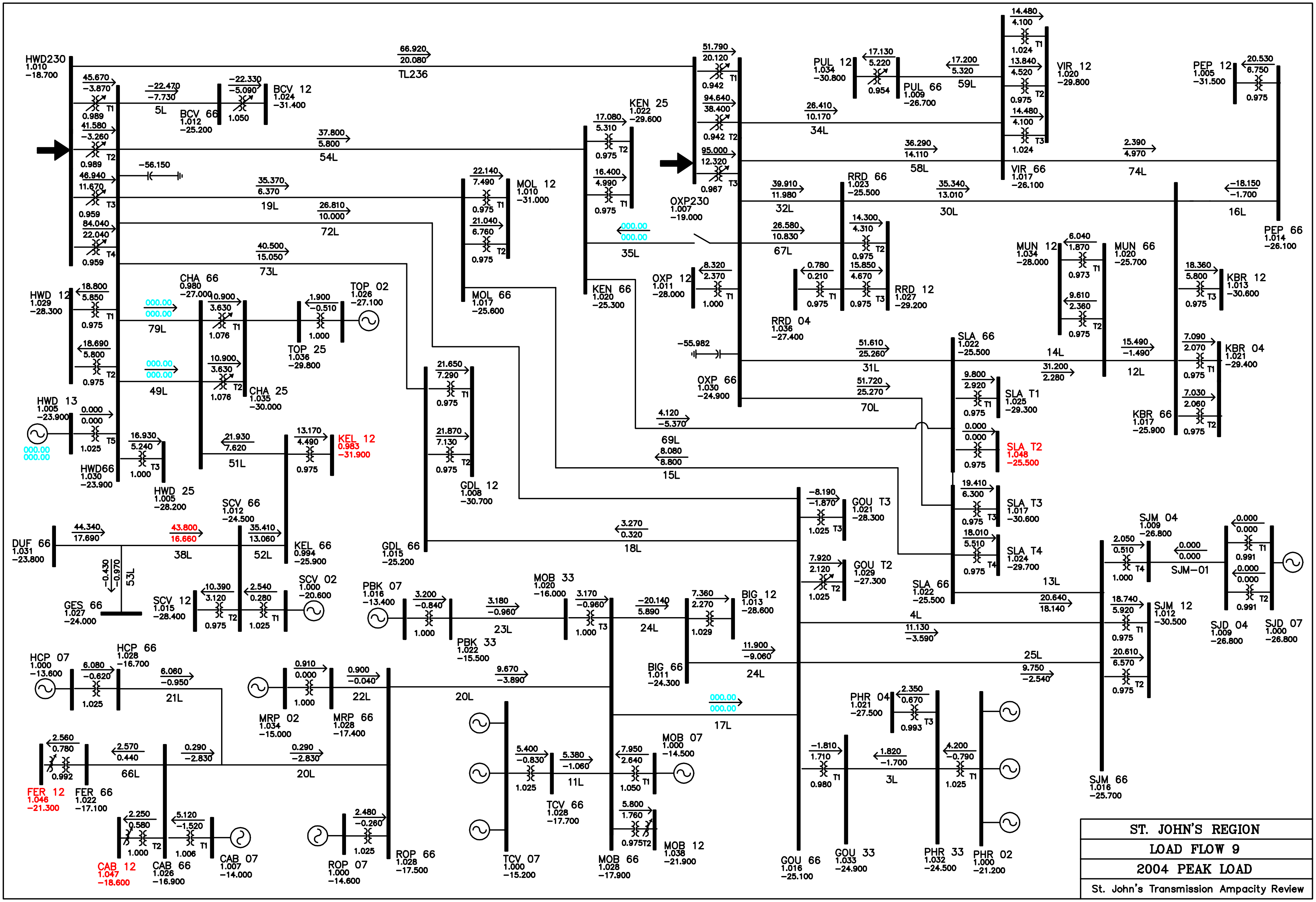


ST. JOHN'S REGION

LOAD FLOW 8

2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION

LOAD FLOW 9

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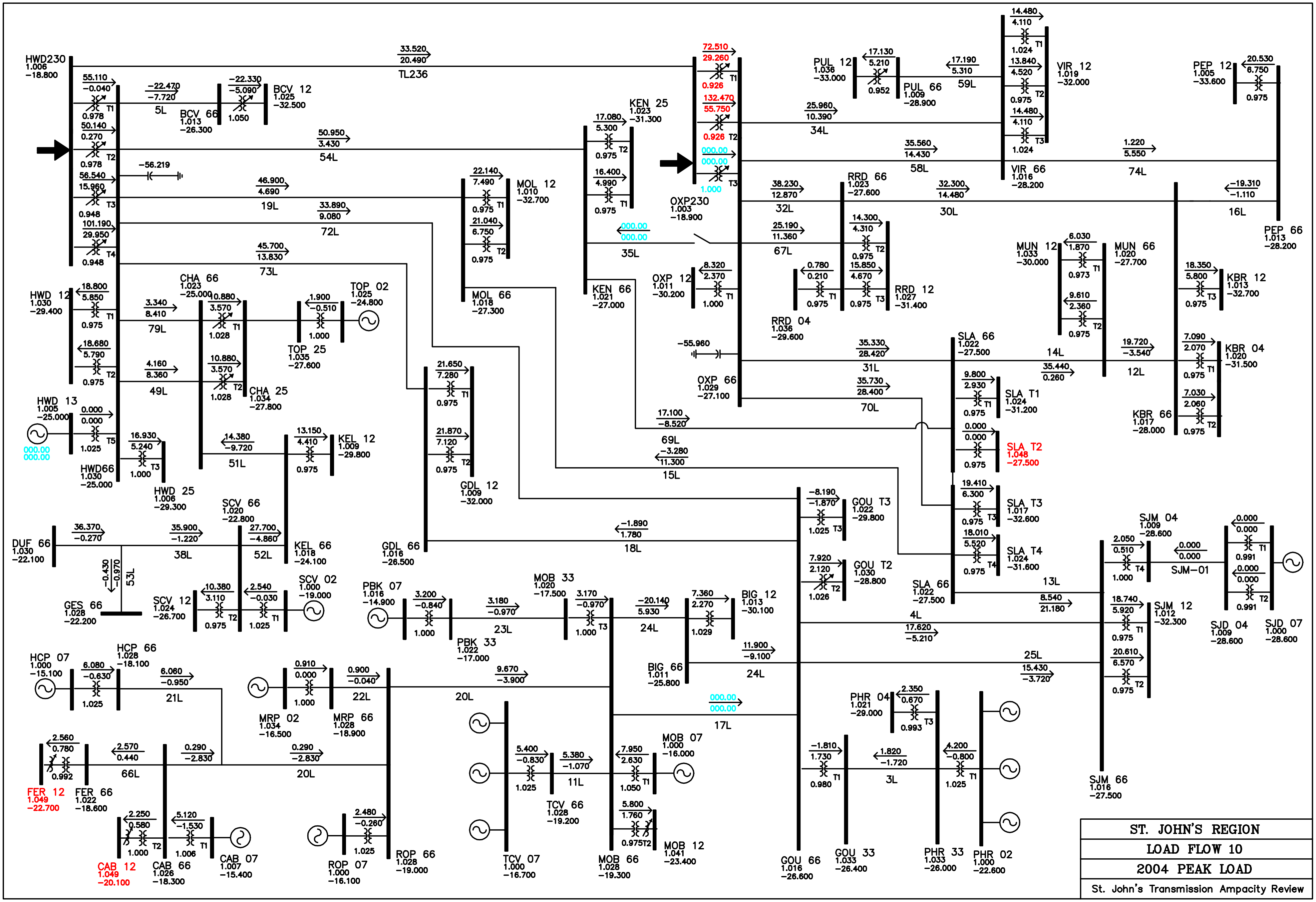
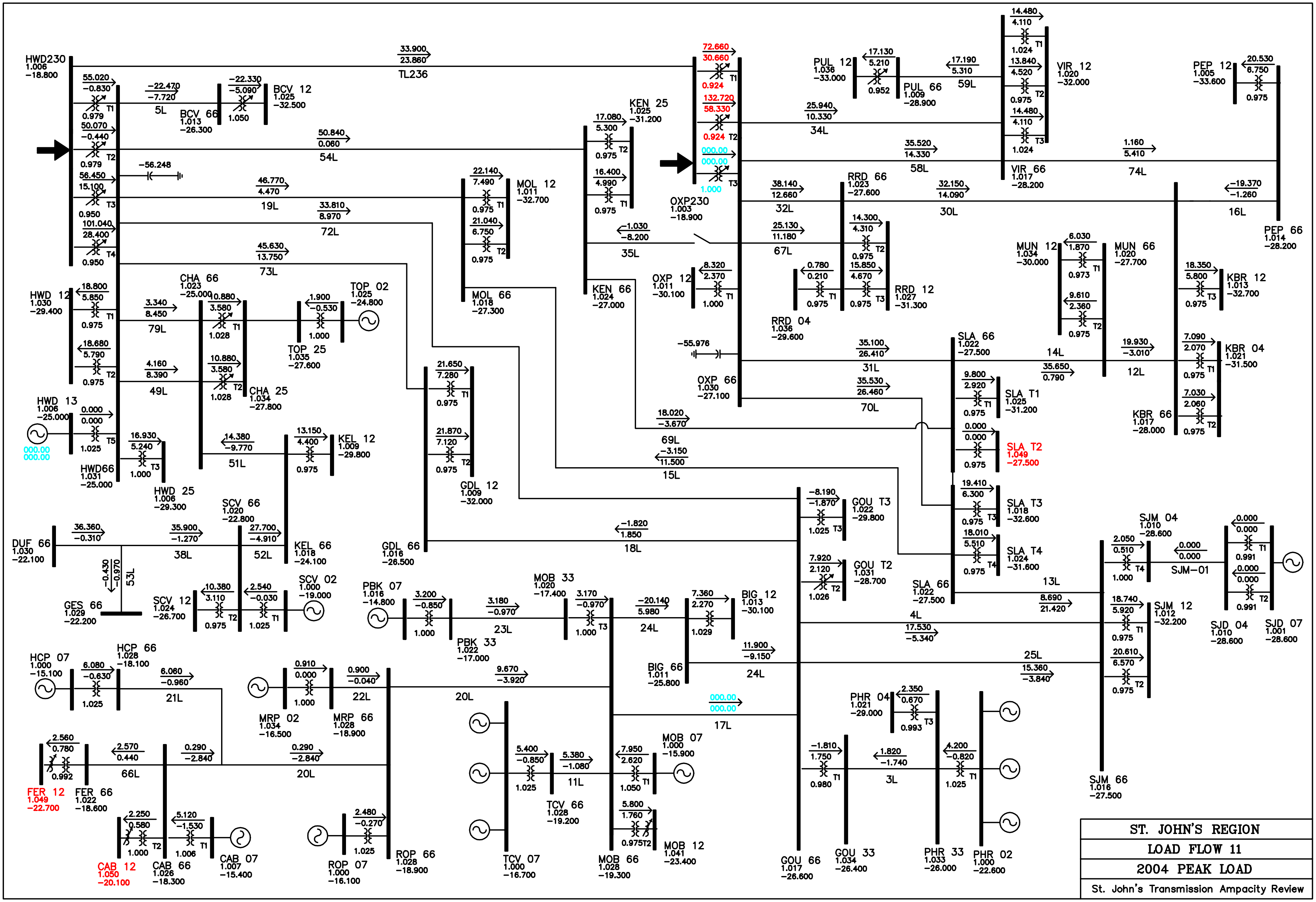


ST. JOHN'S REGION
LOAD FLOW 10
2004 PEAK LOAD
St. John's Transmission Ampacity Review



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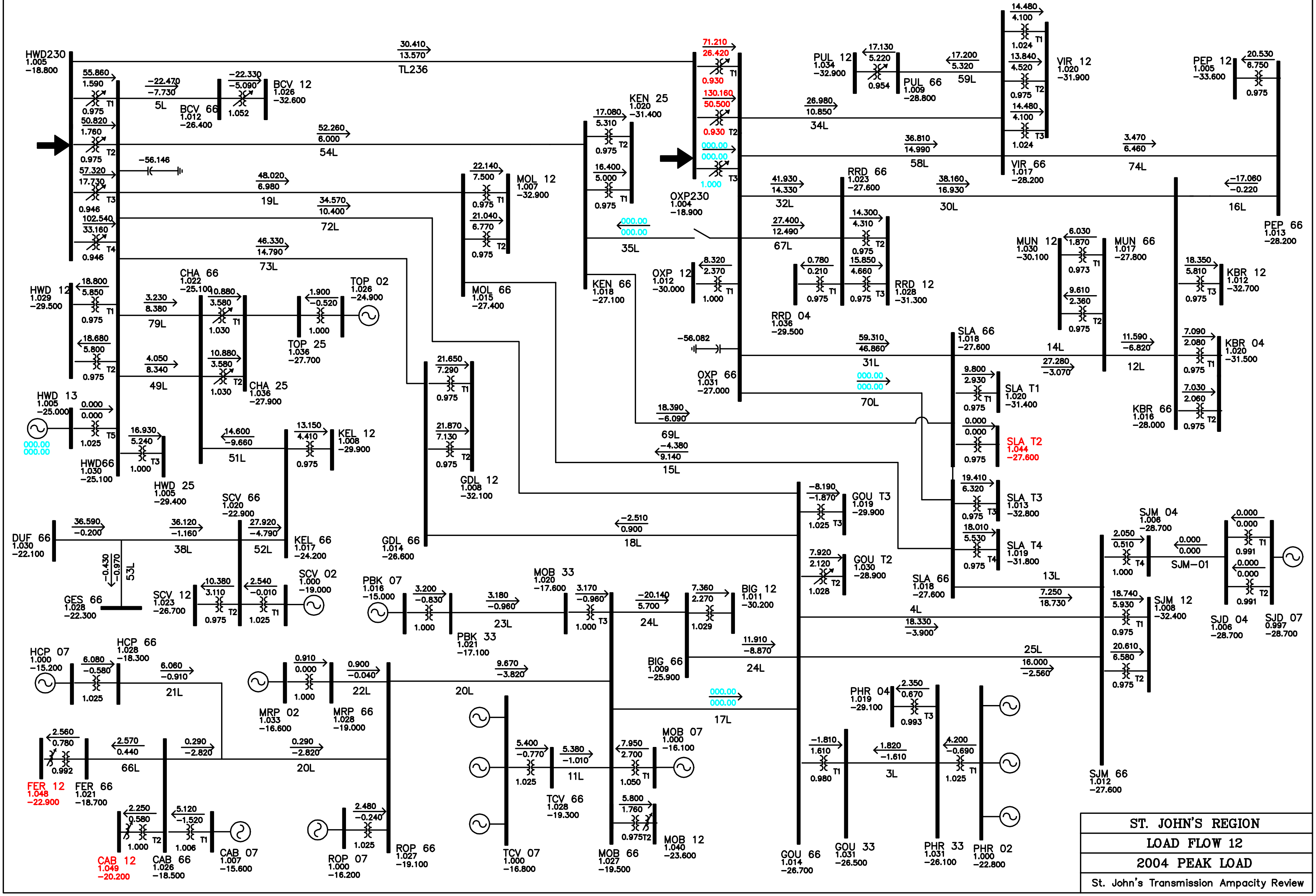
LOAD FLOW 11

2004 PEAK LOAD

St. John's Transmission Ampacity Review

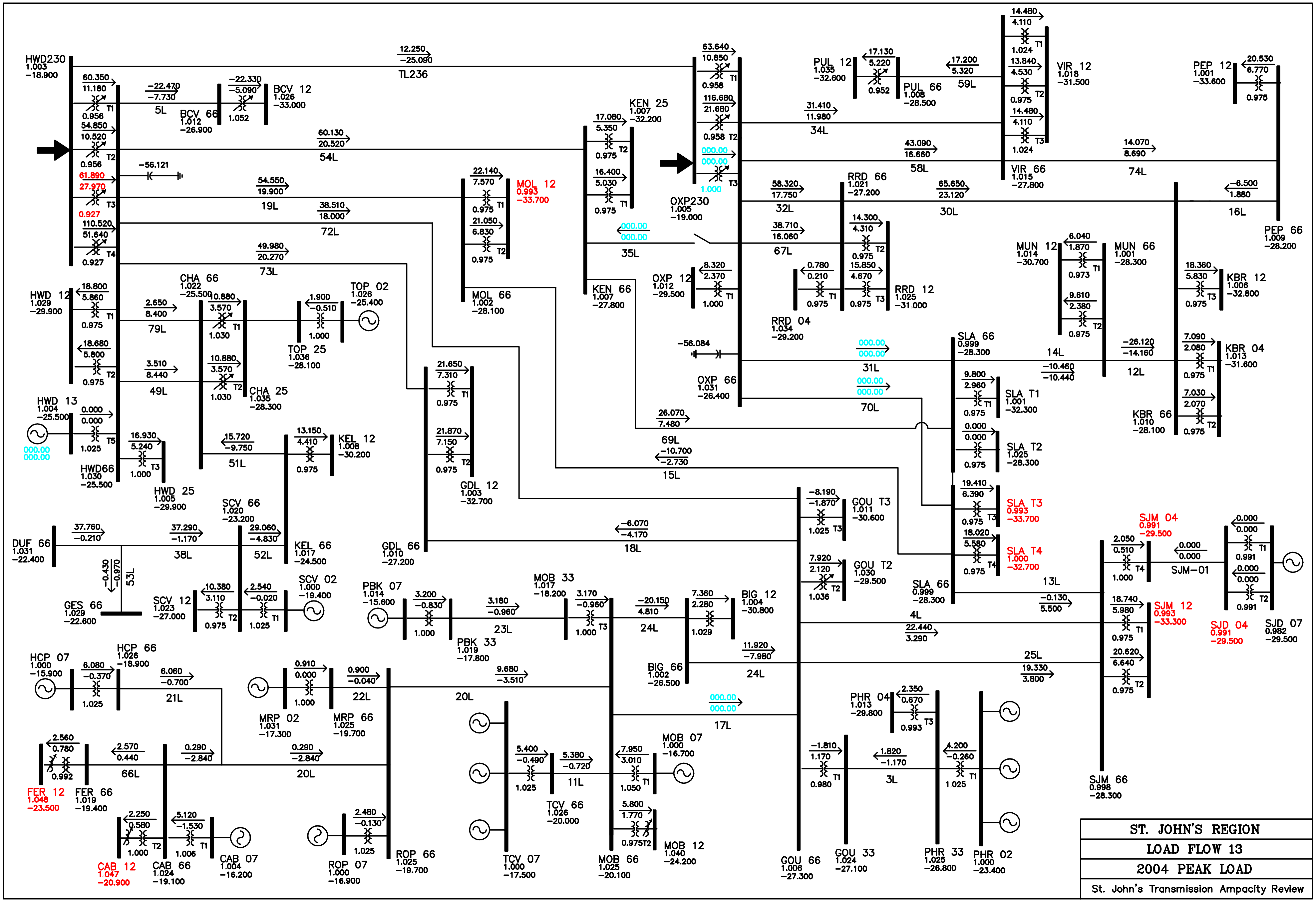


ST. JOHN'S REGION

LOAD FLOW 12

2004 PEAK LOAD

St. John's Transmission Ampacity Review

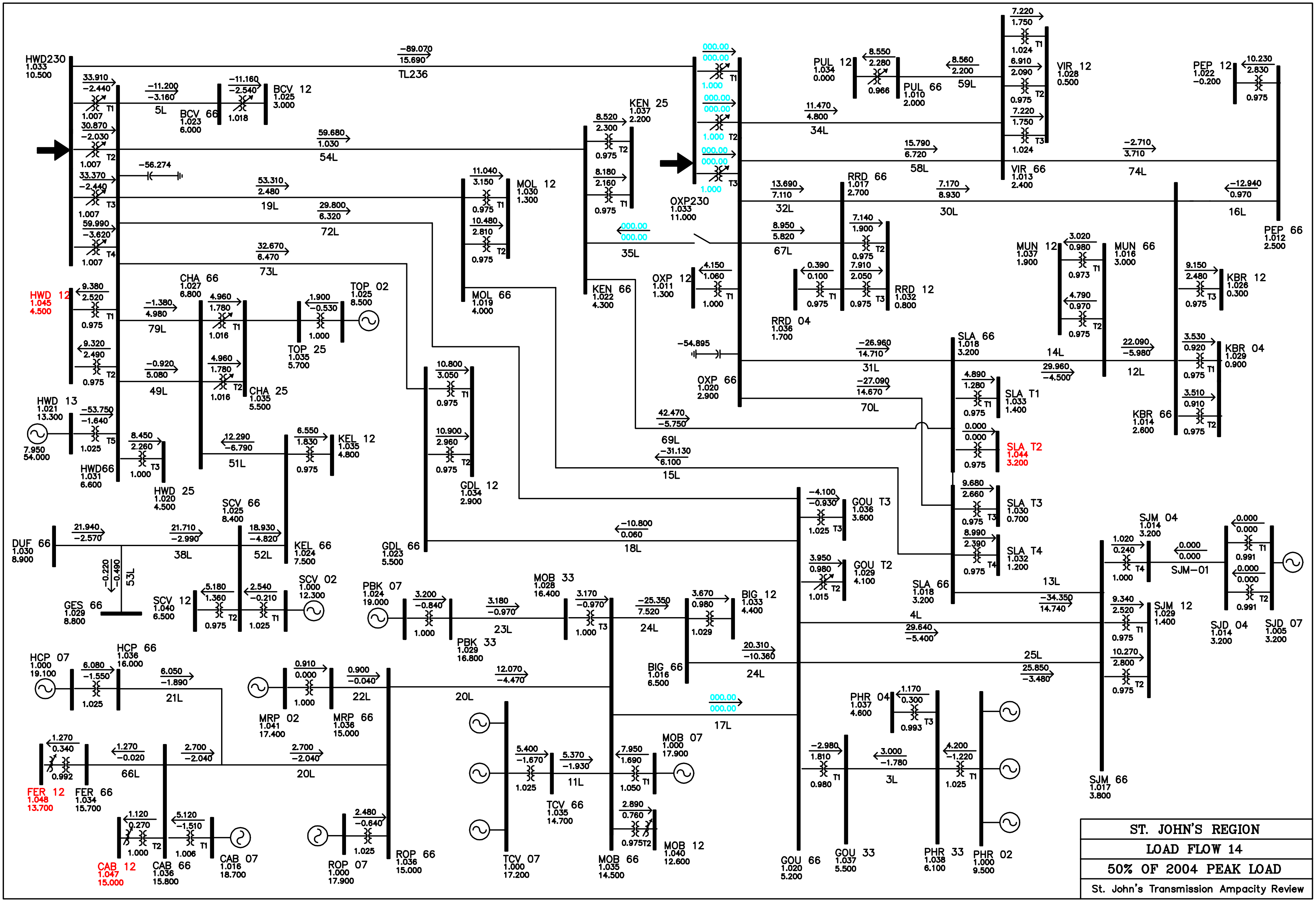


ST. JOHN'S REGION

LOAD FLOW 13

2004 PEAK LOAD

St. John's Transmission Ampacity Review

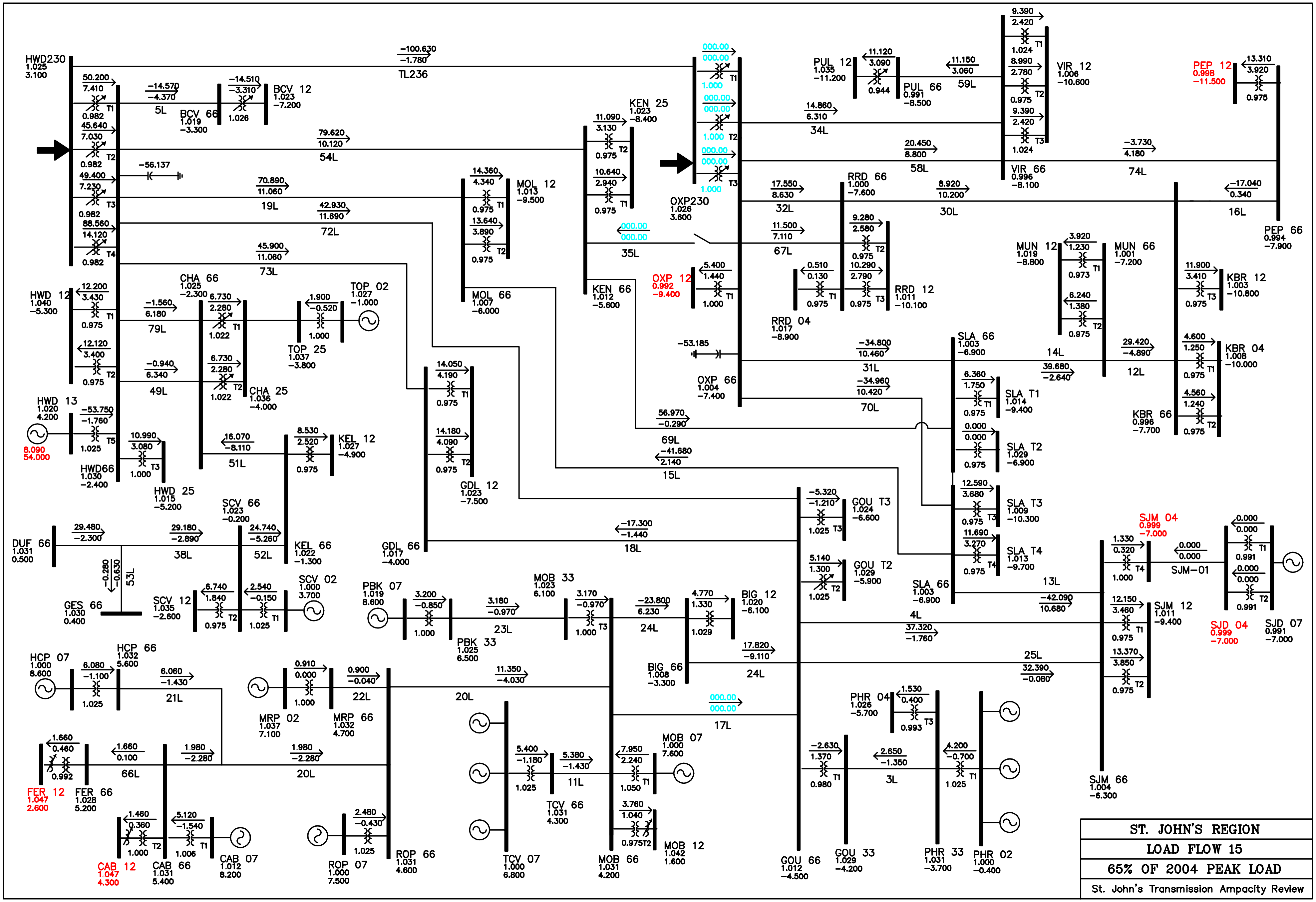


ST. JOHN'S REGION

LOAD FLOW 14

50% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

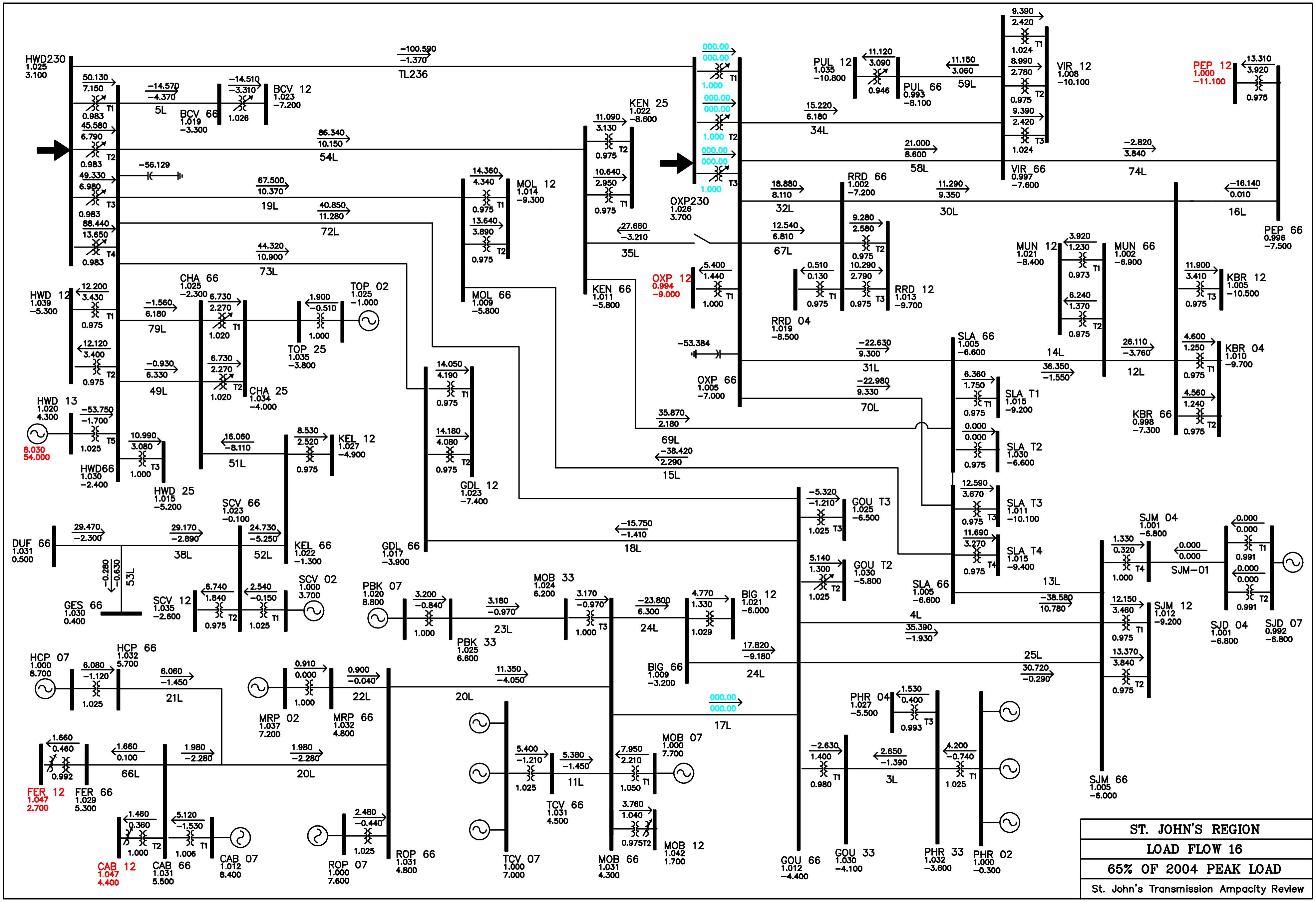


ST. JOHN'S REGION

LOAD FLOW 15

65% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

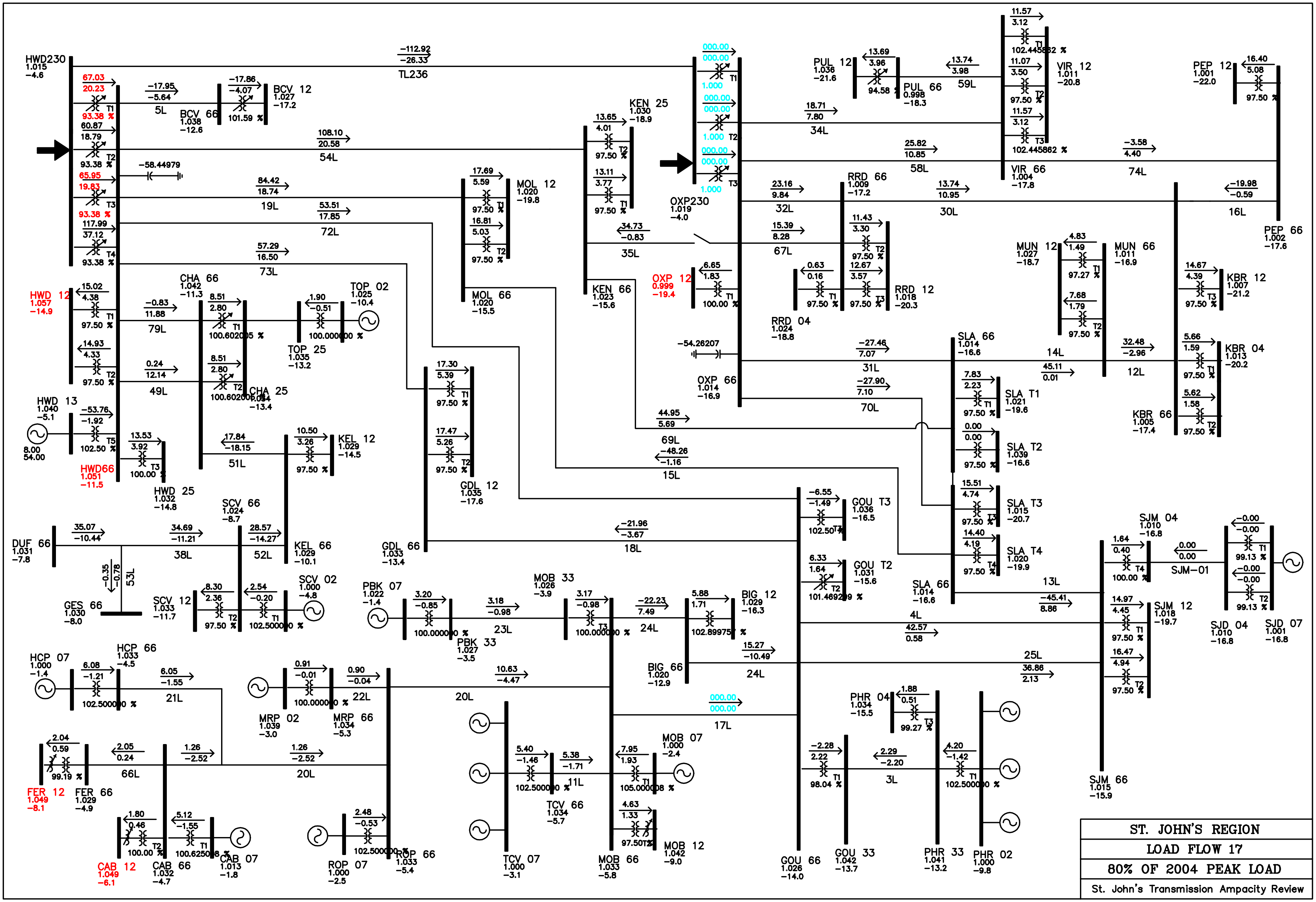


ST. JOHN'S REGION

LOAD FLOW 16

65% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

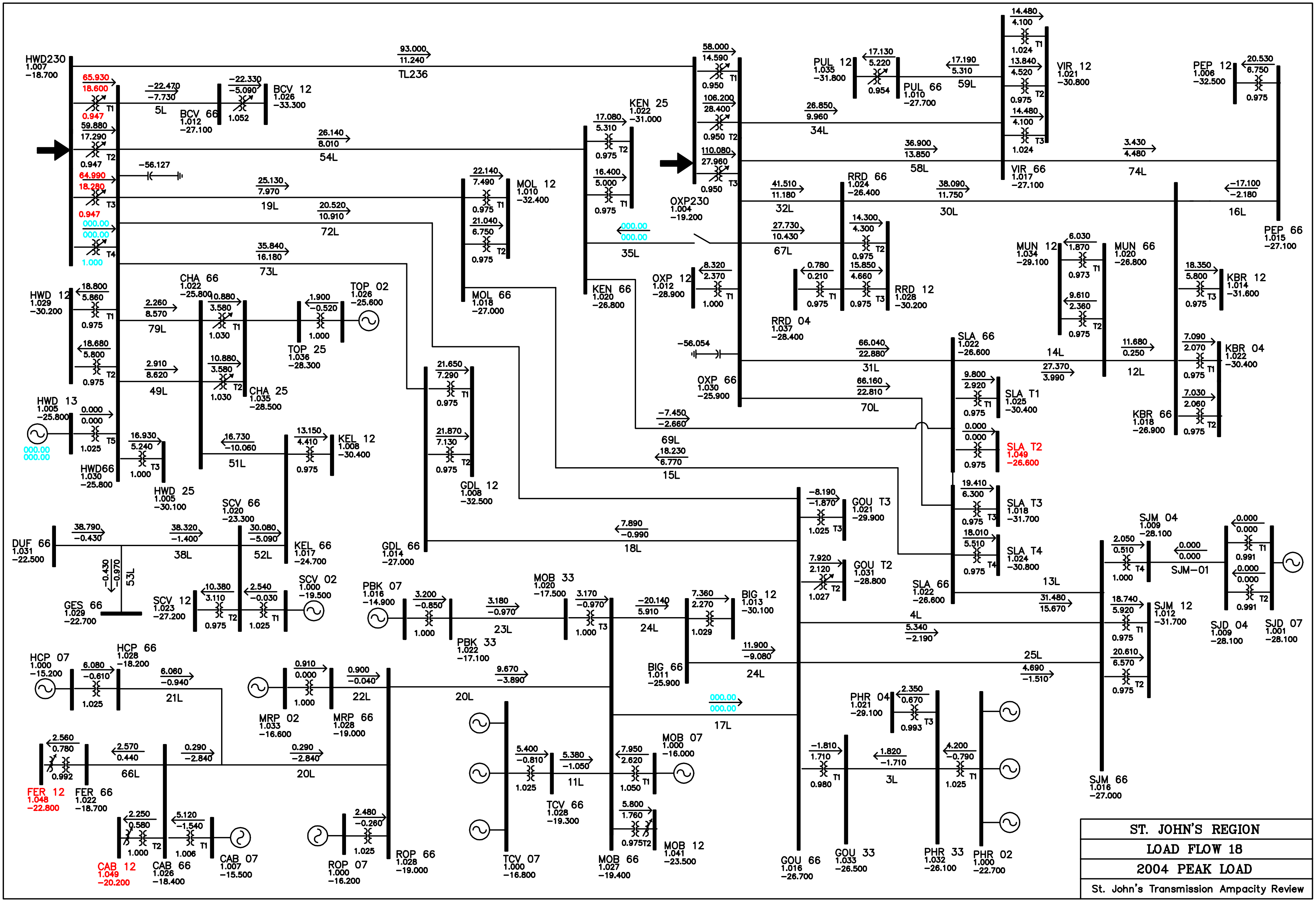


ST. JOHN'S REGION

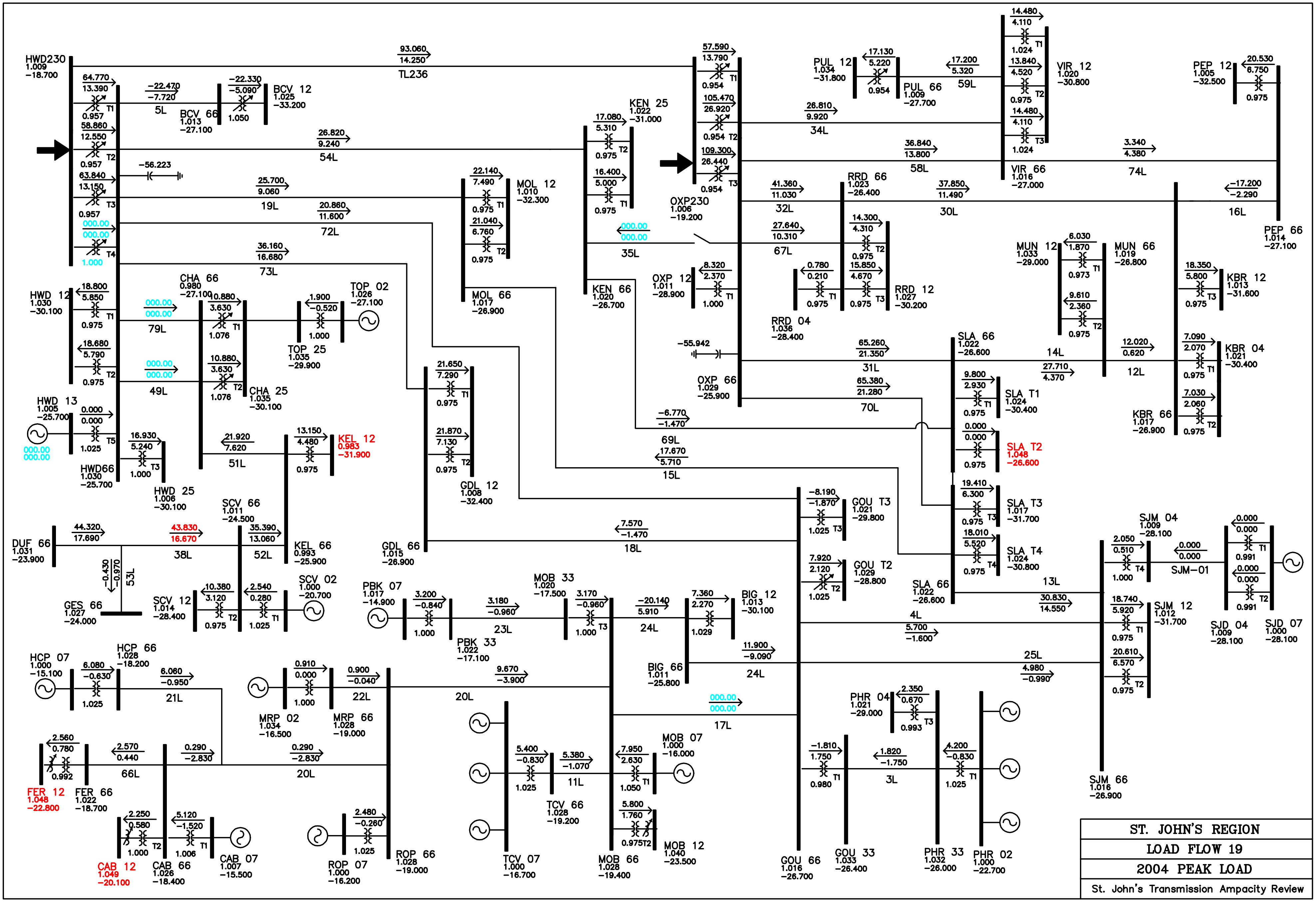
LOAD FLOW 17

80% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 18
2004 PEAK LOAD
St. John's Transmission Ampacity Review



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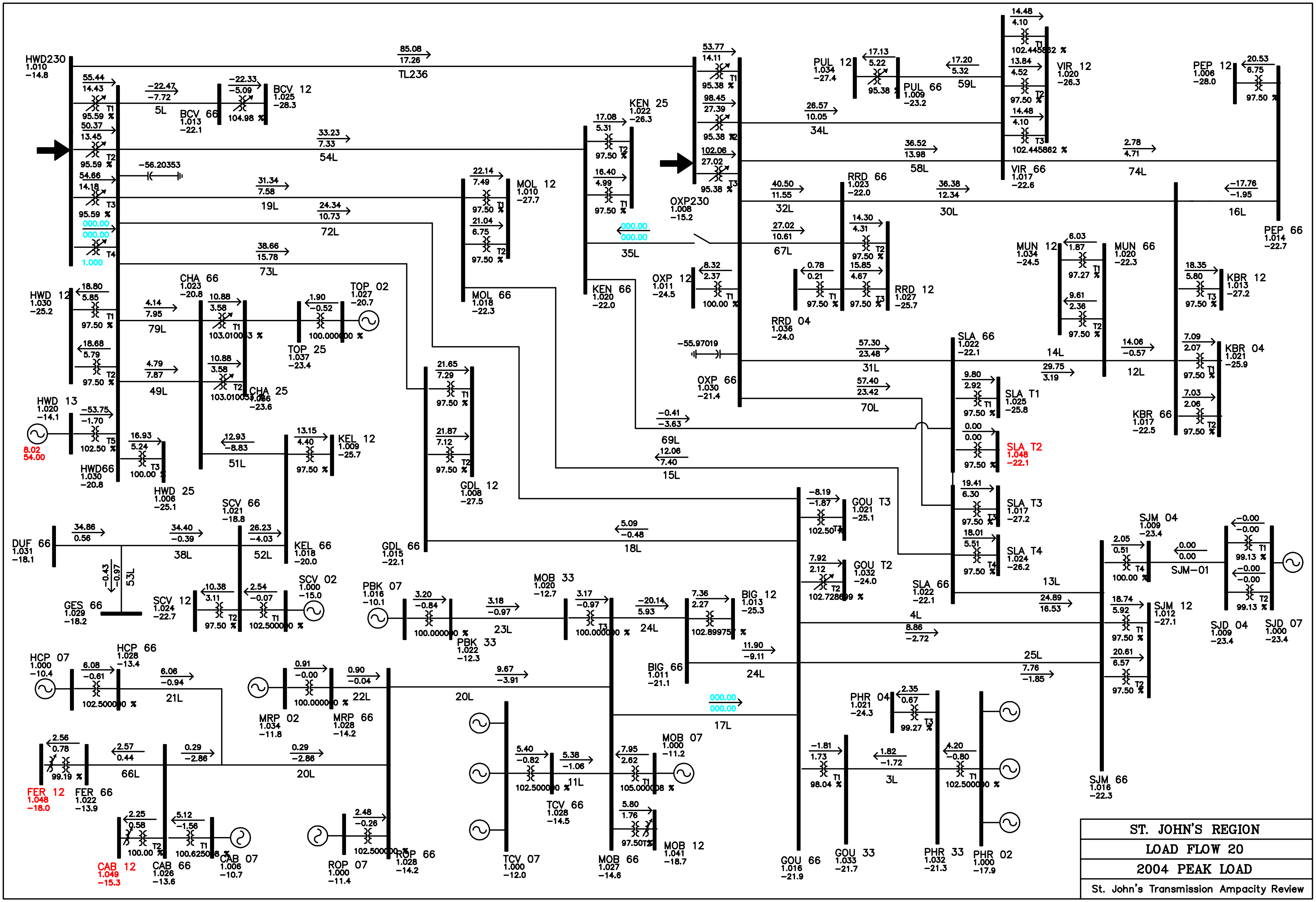
2004 PEAK LOAD
St. John's Transmission Ampacity Review



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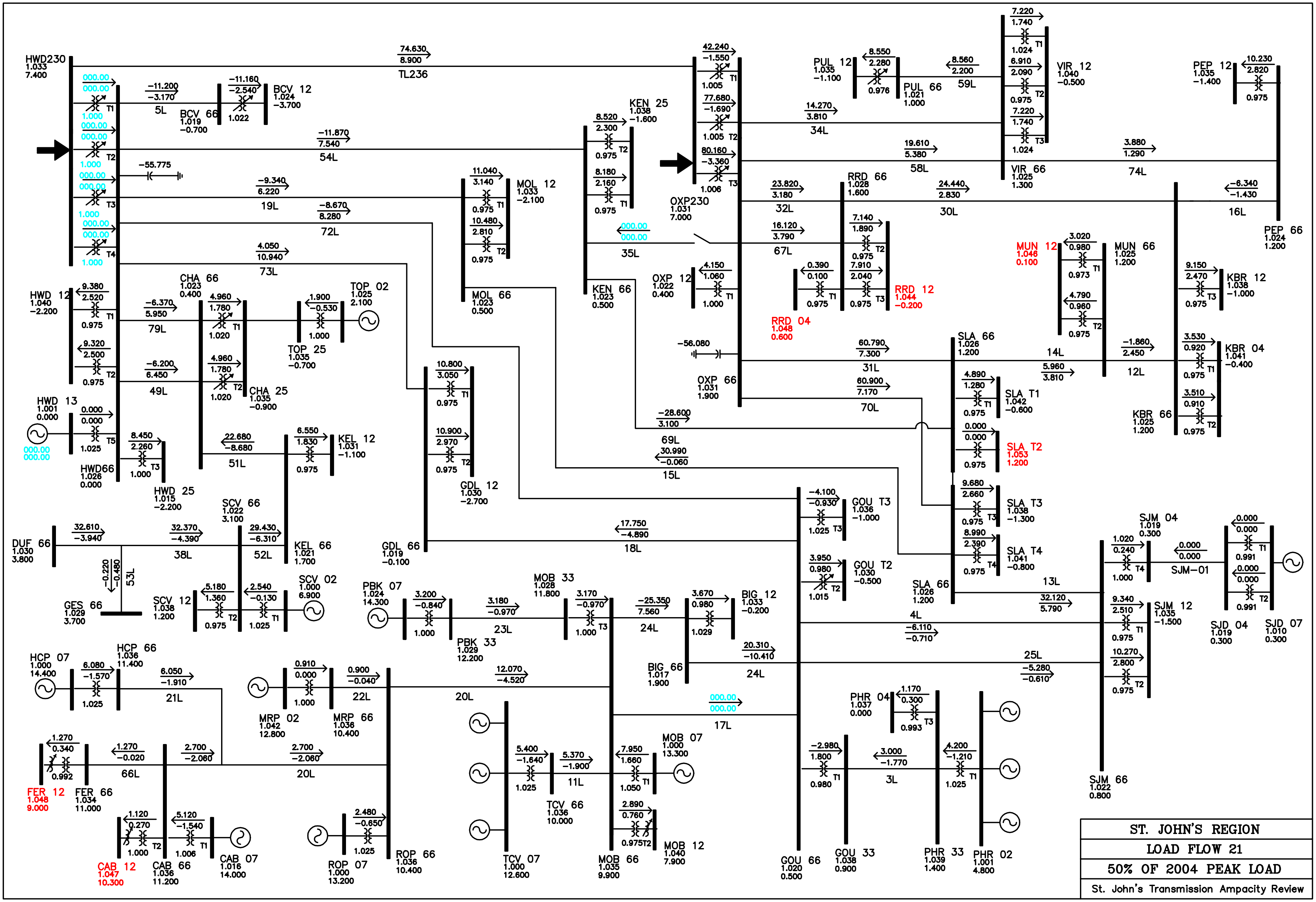
2004 PEAK LOAD
St. John's Transmission Ampacity Review

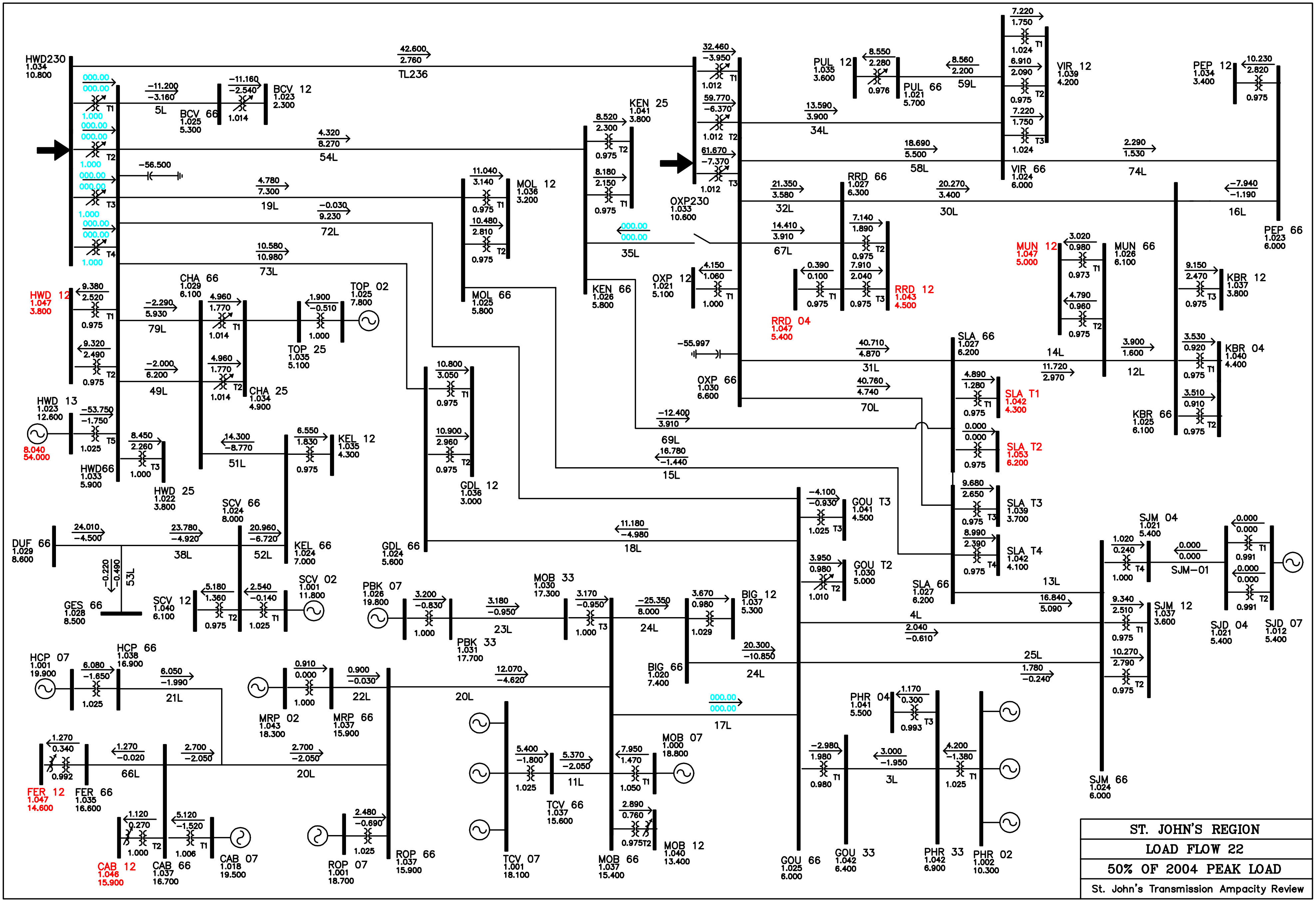


ST. JOHN'S REGION

LOAD FLOW 21

50% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

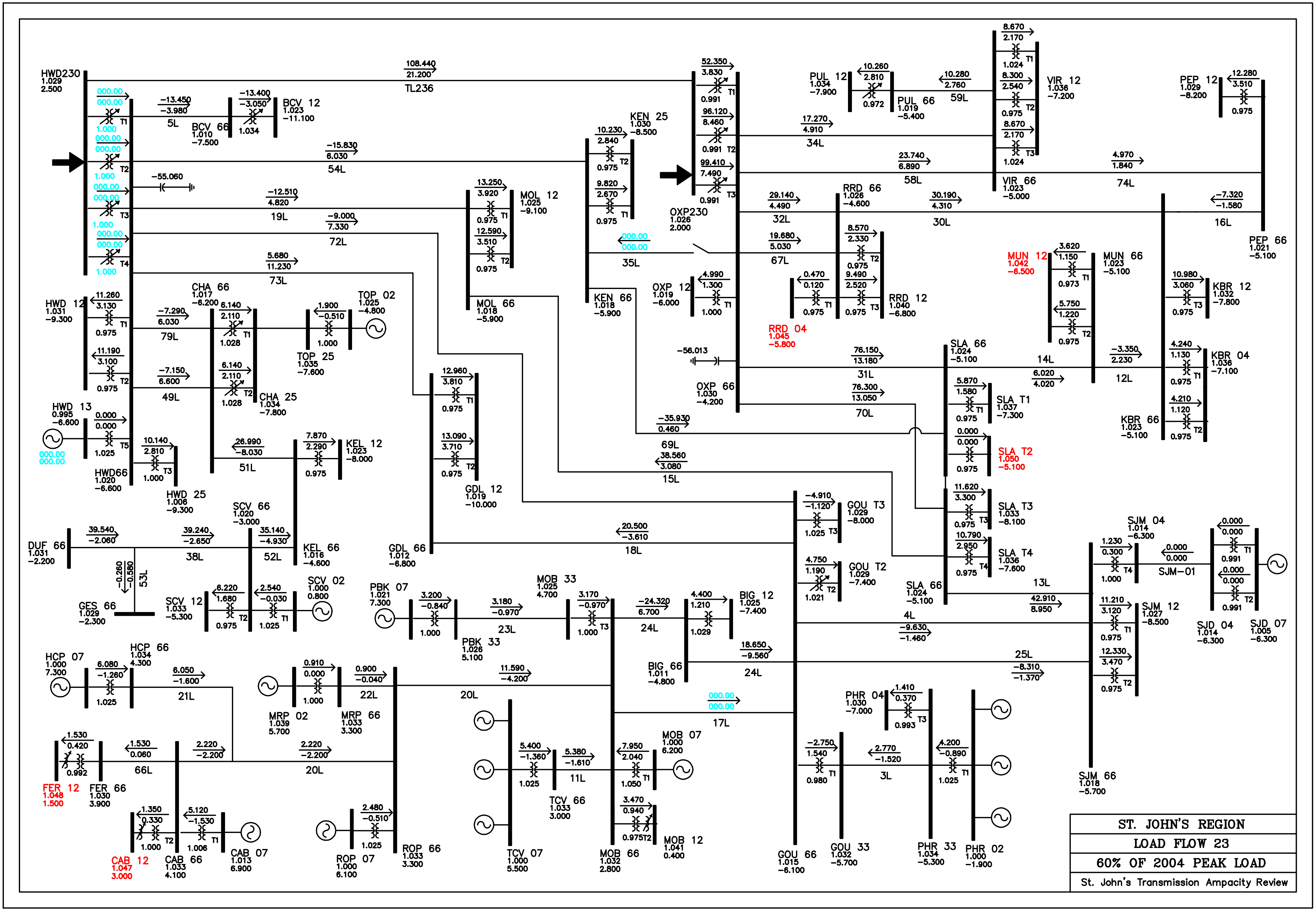


ST. JOHN'S REGION

LOAD FLOW 22

50% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

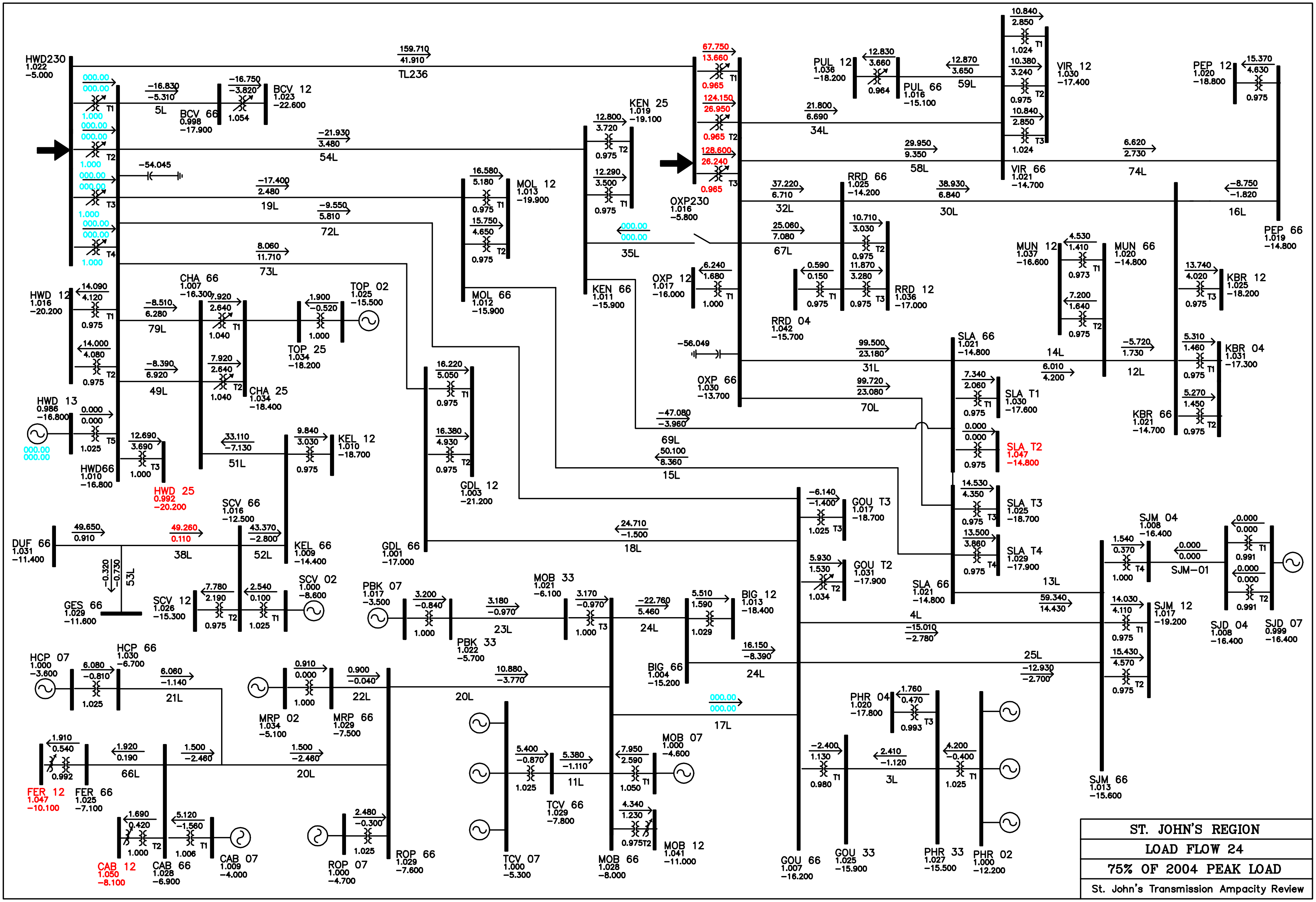


ST. JOHN'S REGION

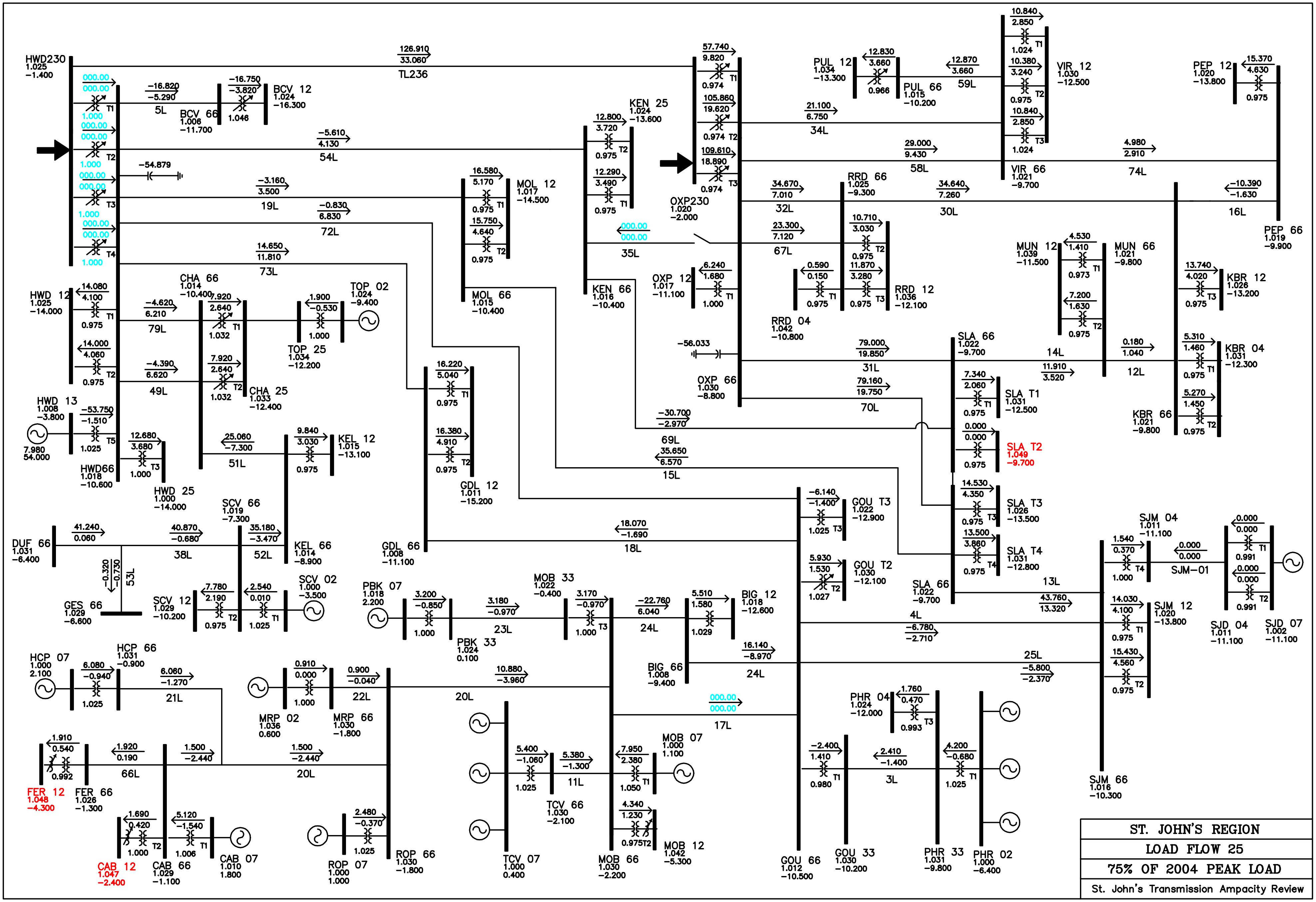
LOAD FLOW 23

60% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 24
75% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review

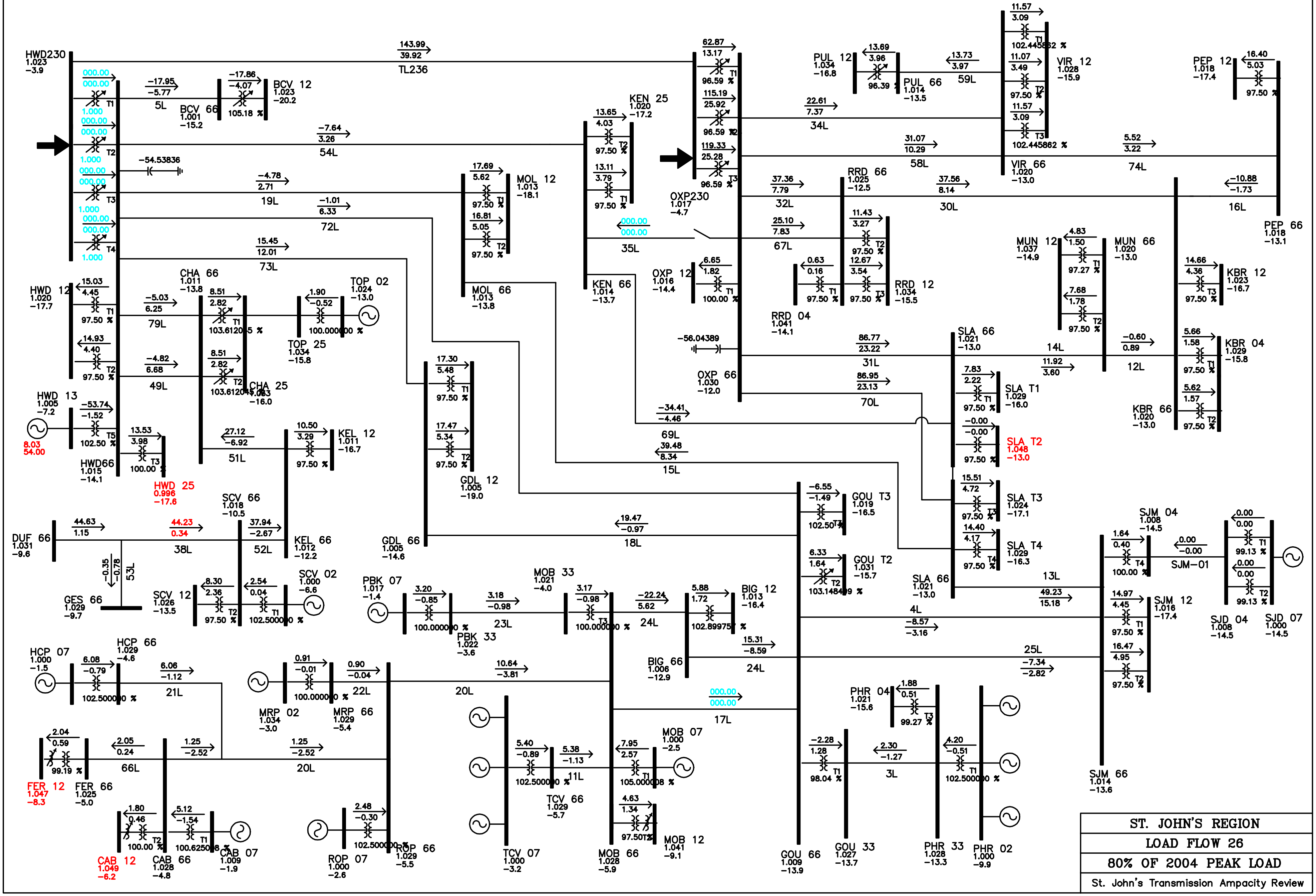


ST. JOHN'S REGION

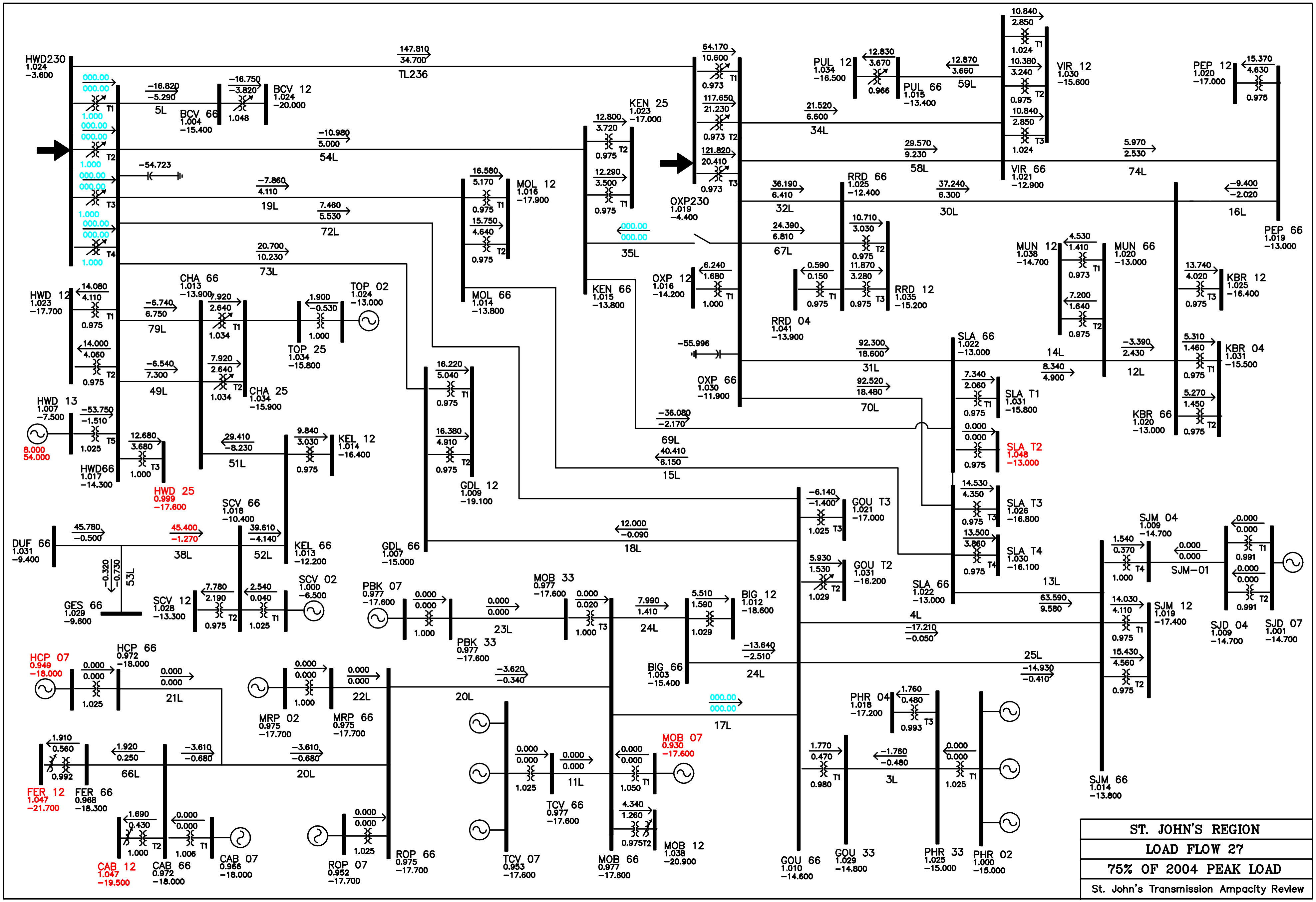
LOAD FLOW 25

75% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 26
80% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review

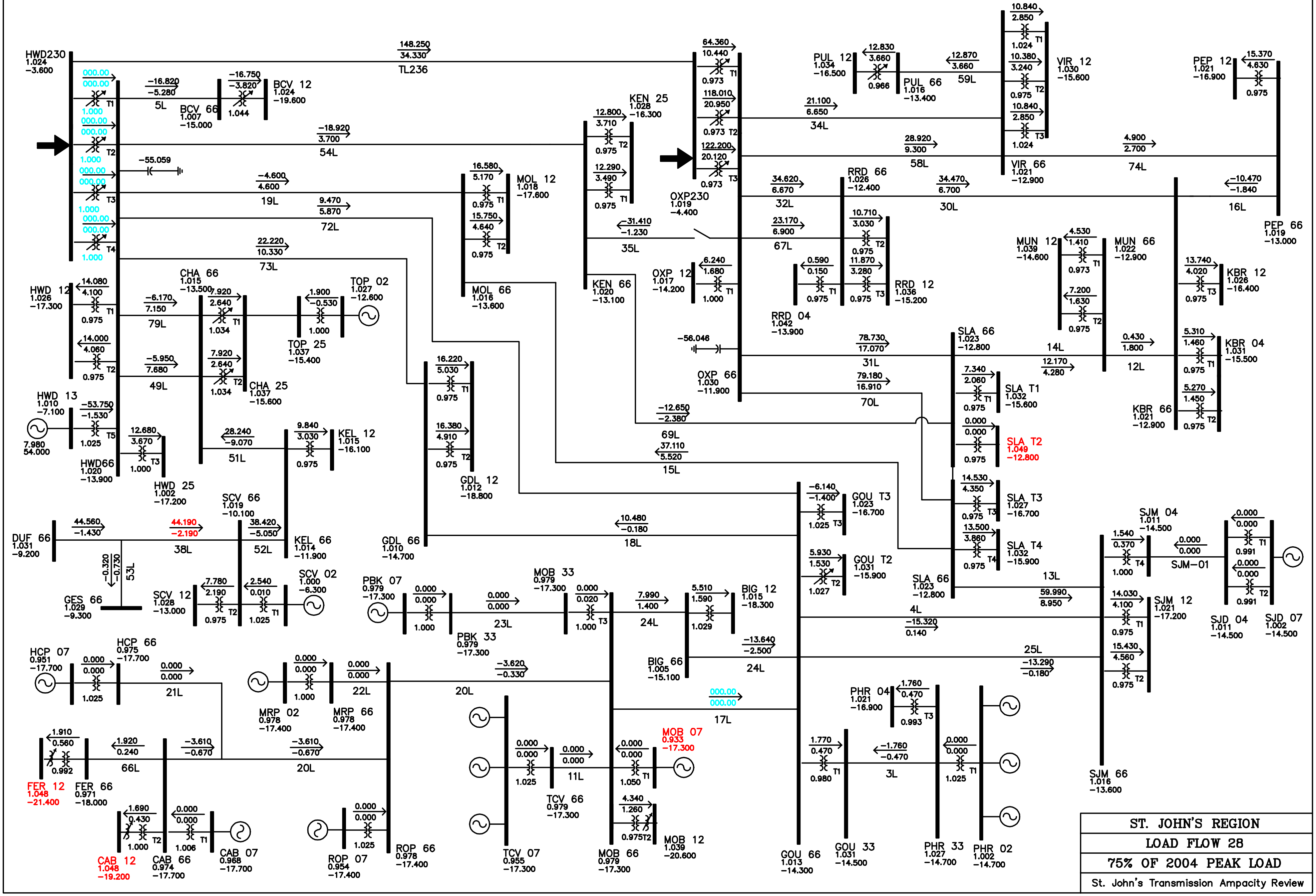


ST. JOHN'S REGION

LOAD FLOW 27

75% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review

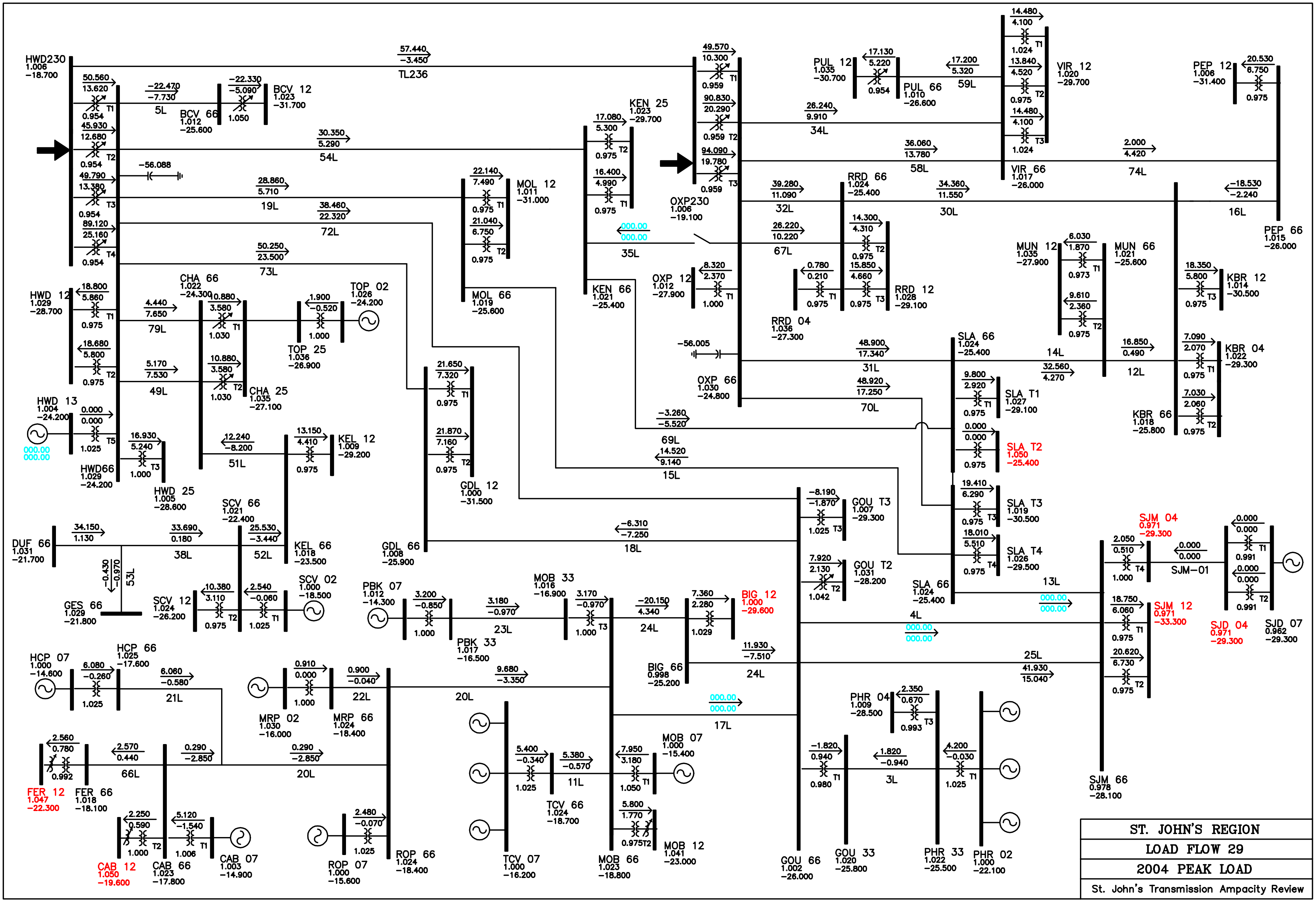


ST. JOHN'S REGION

LOAD FLOW 28

75% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION

LOAD FLOW 29

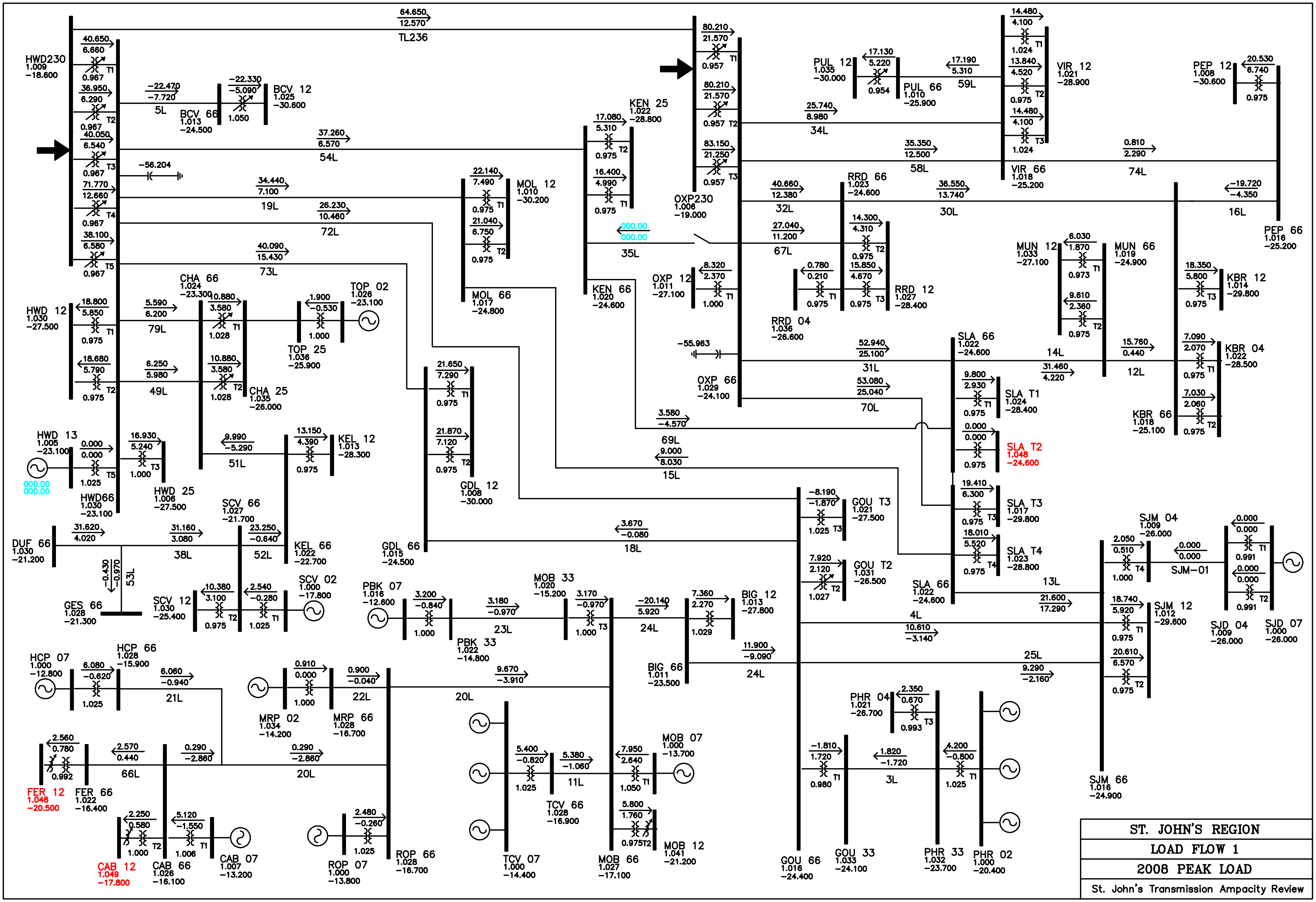
2004 PEAK LOAD

St. John's Transmission Ampacity Review

APPENDIX B
2008 LOAD FLOW DRAWINGS

Index

1. Base case 2008 peak loads
2. Base case, open two lines OXP-VIR (34L and 58L), raise OXP voltage to 1.05 pu
3. As in #2, and open MUN-KBR (12L)
4. Base case, Open one line OXP-VIR (58L), raise OXP voltage to 1.05 pu, and open MUN-KBR (12L)
5. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu
6. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu and open MUN-KBR (12L)
7. Base case, open two lines OXP-SLA (31L and 70L)
8. As in #7, close OXP-KEN (35L)
9. Base case, open two lines HWD-CHA (79L and 49L)
10. Base case, open 125 MVA transformer at OXP 230/66
11. As in #10, close OXP-KEN (35L)
12. As in #10, open OXP-SLA (70L)
13. As in #10, open two lines OXP-SLA (31L and 70L)
14. 50% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
15. 65% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
16. As in #15, close OXP-KEN (35L)
17. 80% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on, HWD voltage to 1.05 pu, close OXP-KEN (35L)
18. Base case, open 125 MVA transformer at HWD 230/66
19. As in #18, open two lines OXP-CHA (79L and 49L)
20. As in #18, HWD GT on
21. 50% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
22. As in #21, HWD GT on
23. 60% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
24. 75% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
25. As in #24, HWD GT on
26. 80% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4), HWD GT on
27. As in #26, HWD GT on, no Southern Shore generation, HWD GT off
28. As in #27, HWD GT on, no Southern Shore generation, close OXP-KEN (35L)
29. Base case, open SJM-SLA (13L) and SJM – GOU (4L)

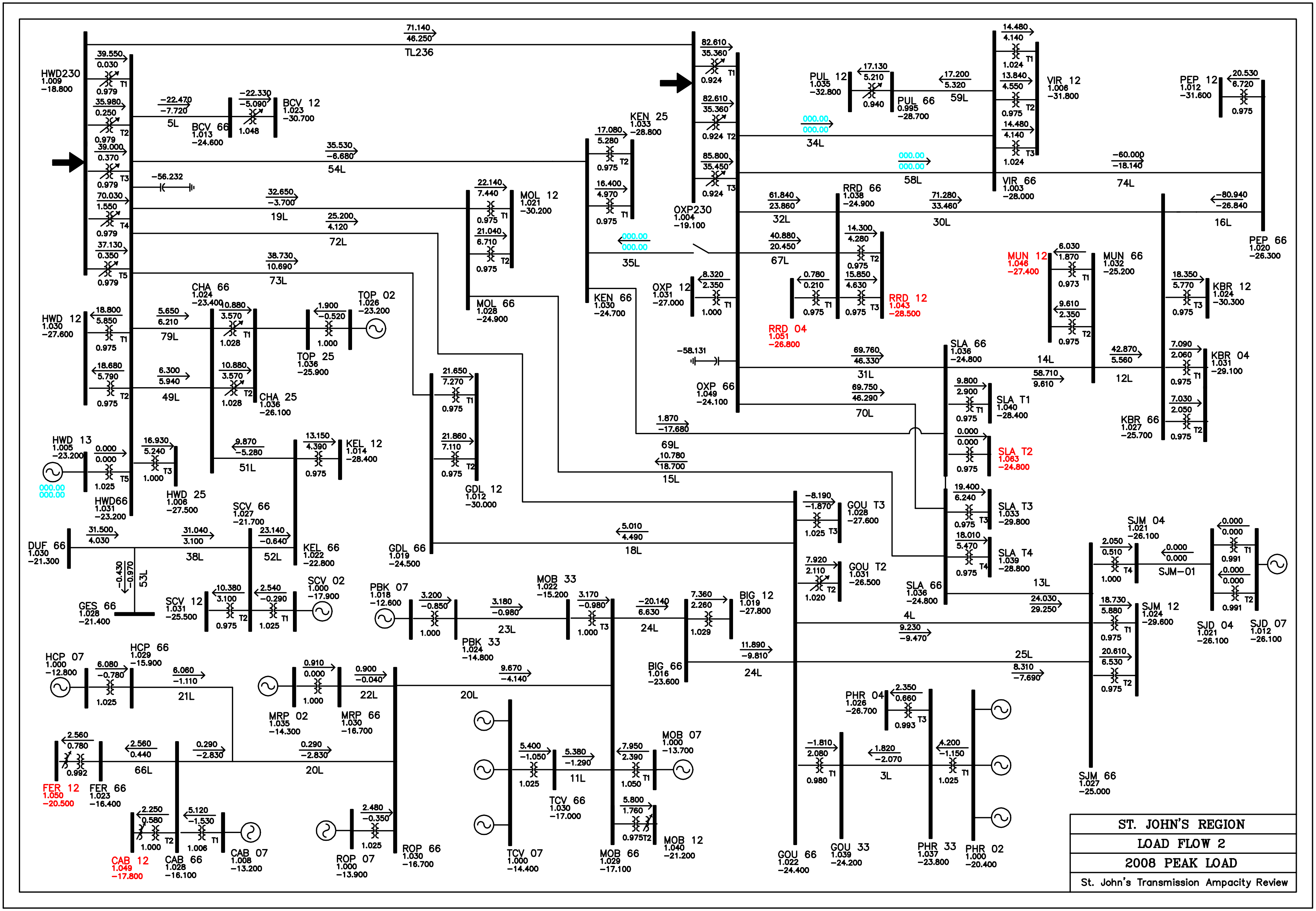


ST. JOHN'S REGION

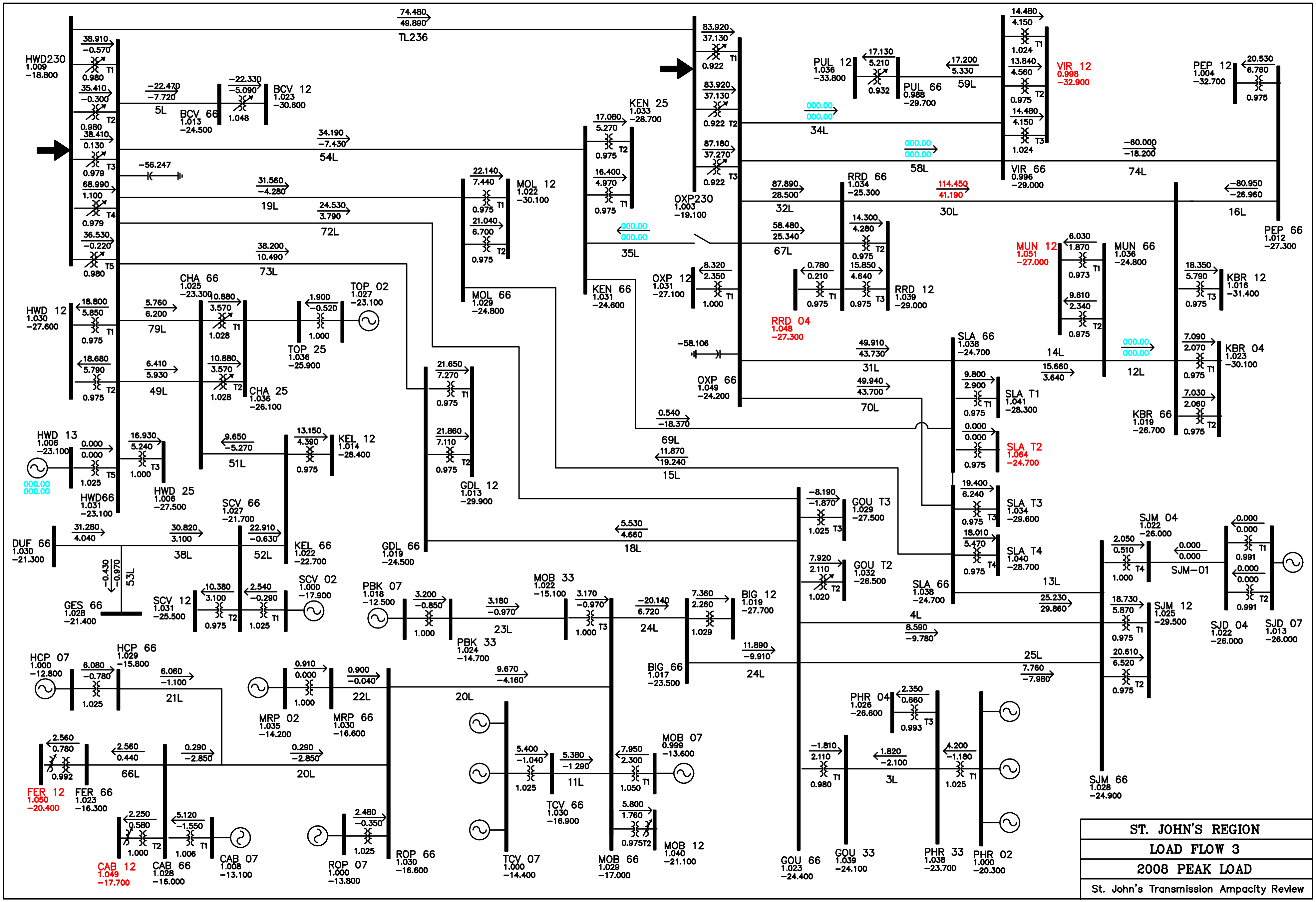
LOAD FLOW 1

2008 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 2
2008 PEAK LOAD
St. John's Transmission Ampacity Review



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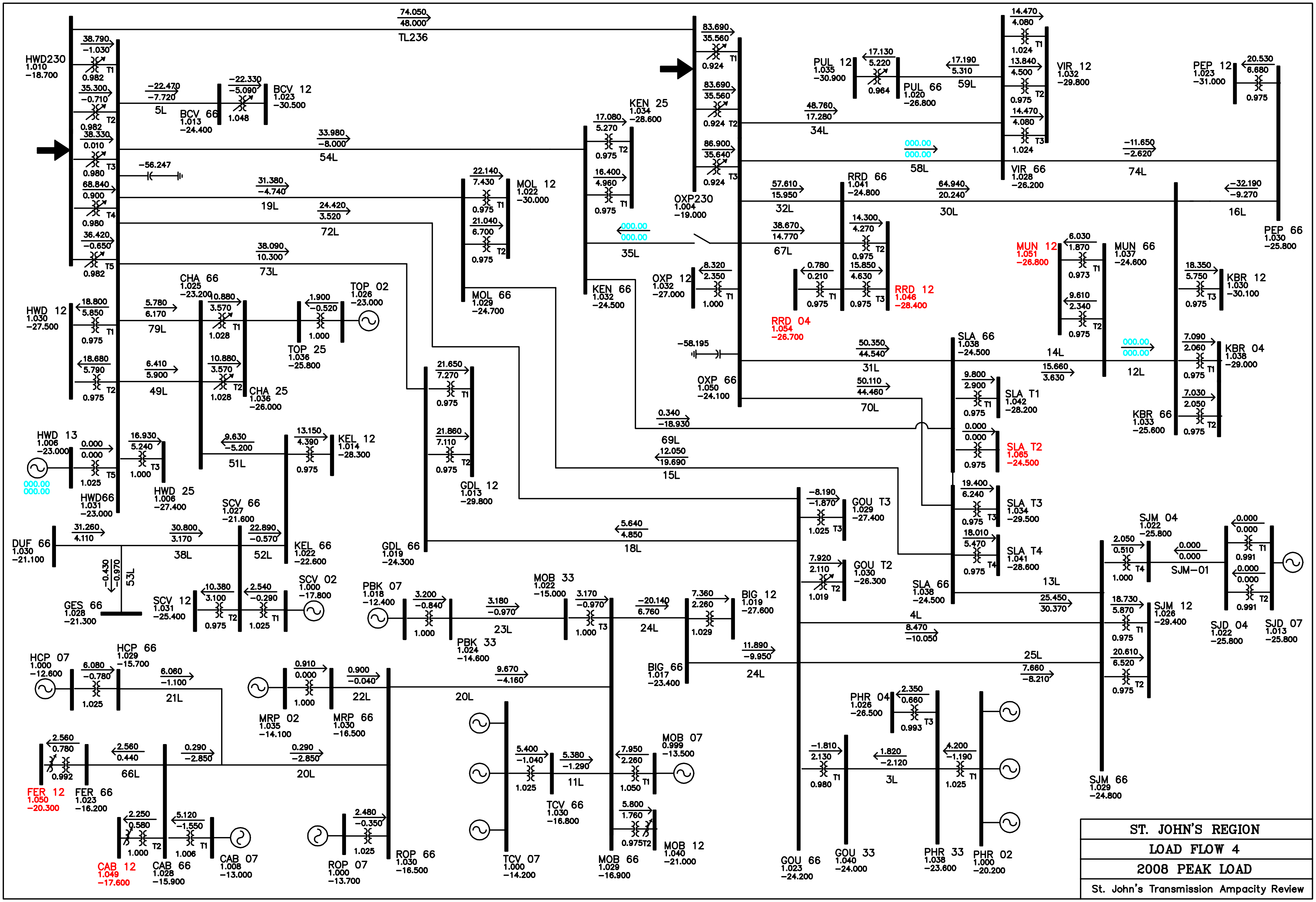
St. John's Transmission Ampacity Review



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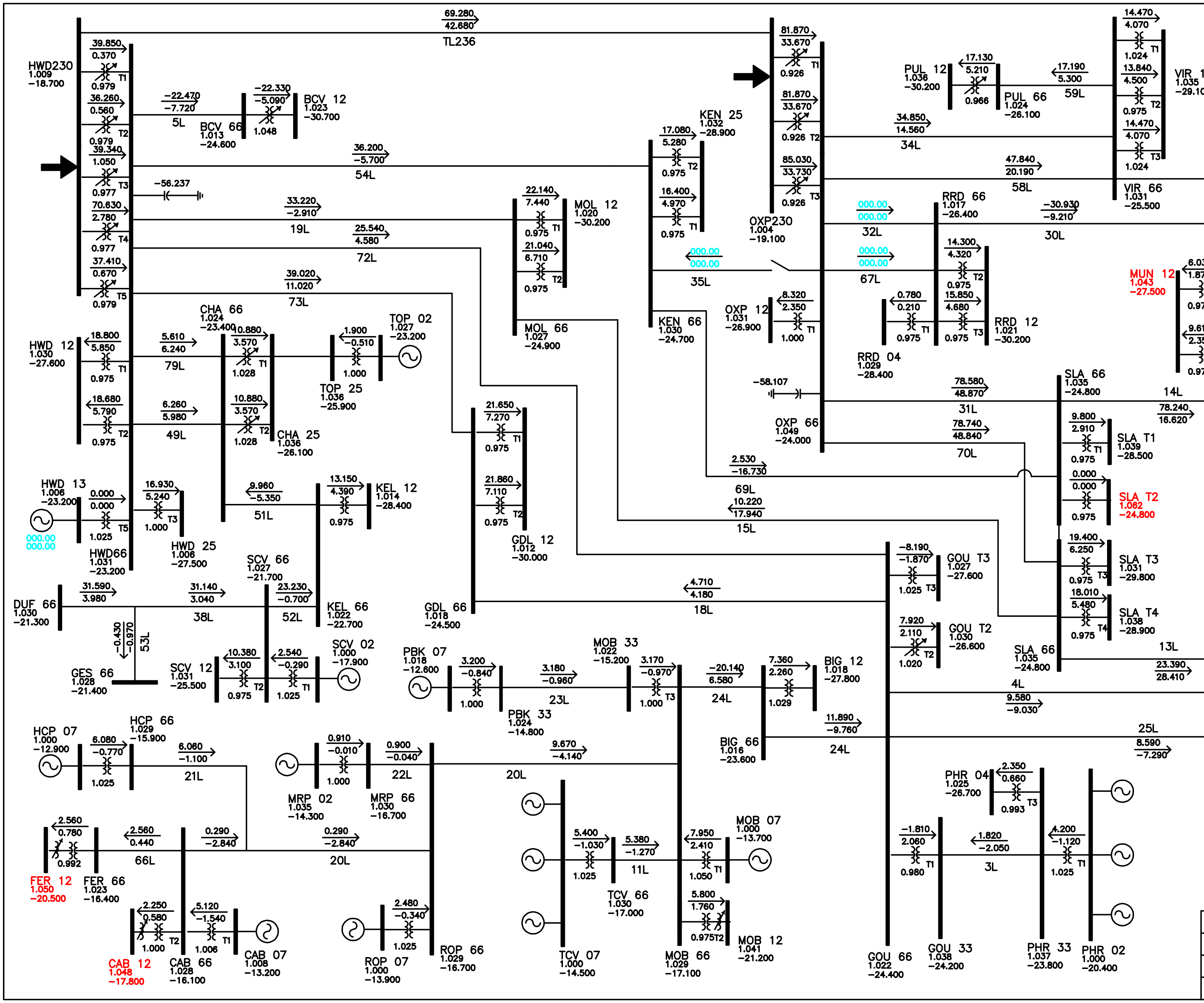
St. John's Transmission Ampacity Review



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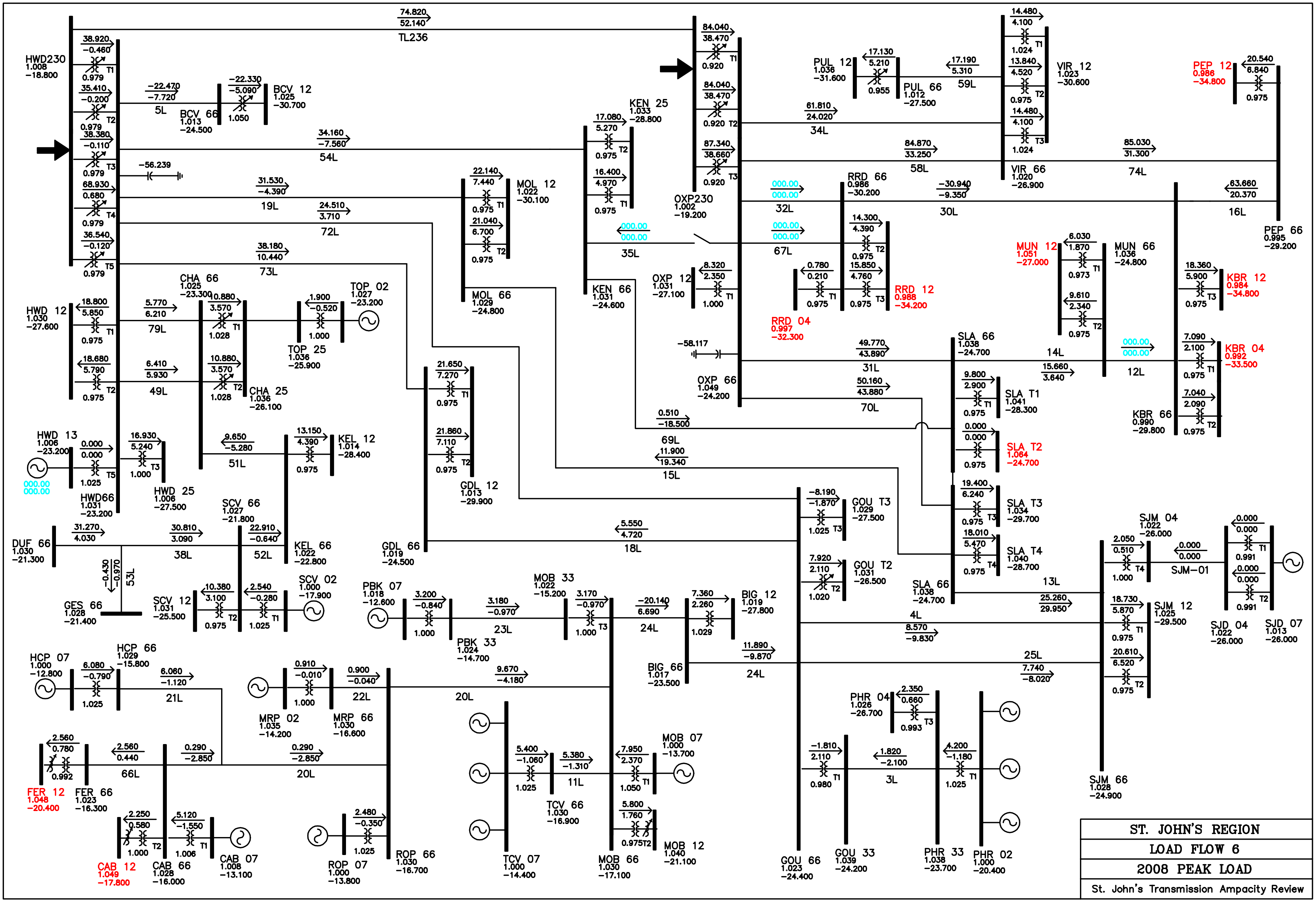
LOAD FLOW 5

2008 PEAK LOAD

St. John's Transmission Ampacity Review

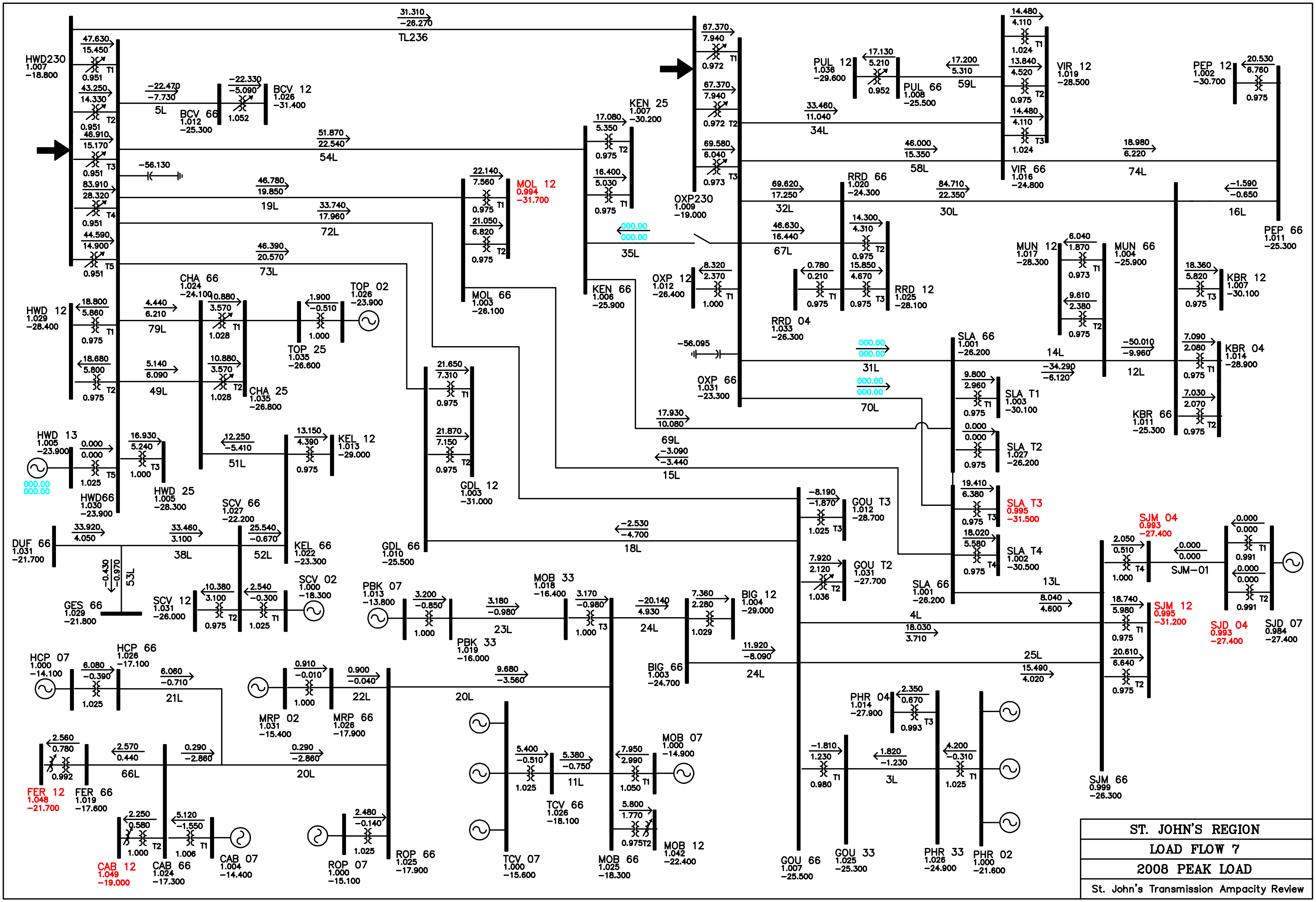


ST. JOHN'S REGION

LOAD FLOW 6

2008 PEAK LOAD

St. John's Transmission Ampacity Review

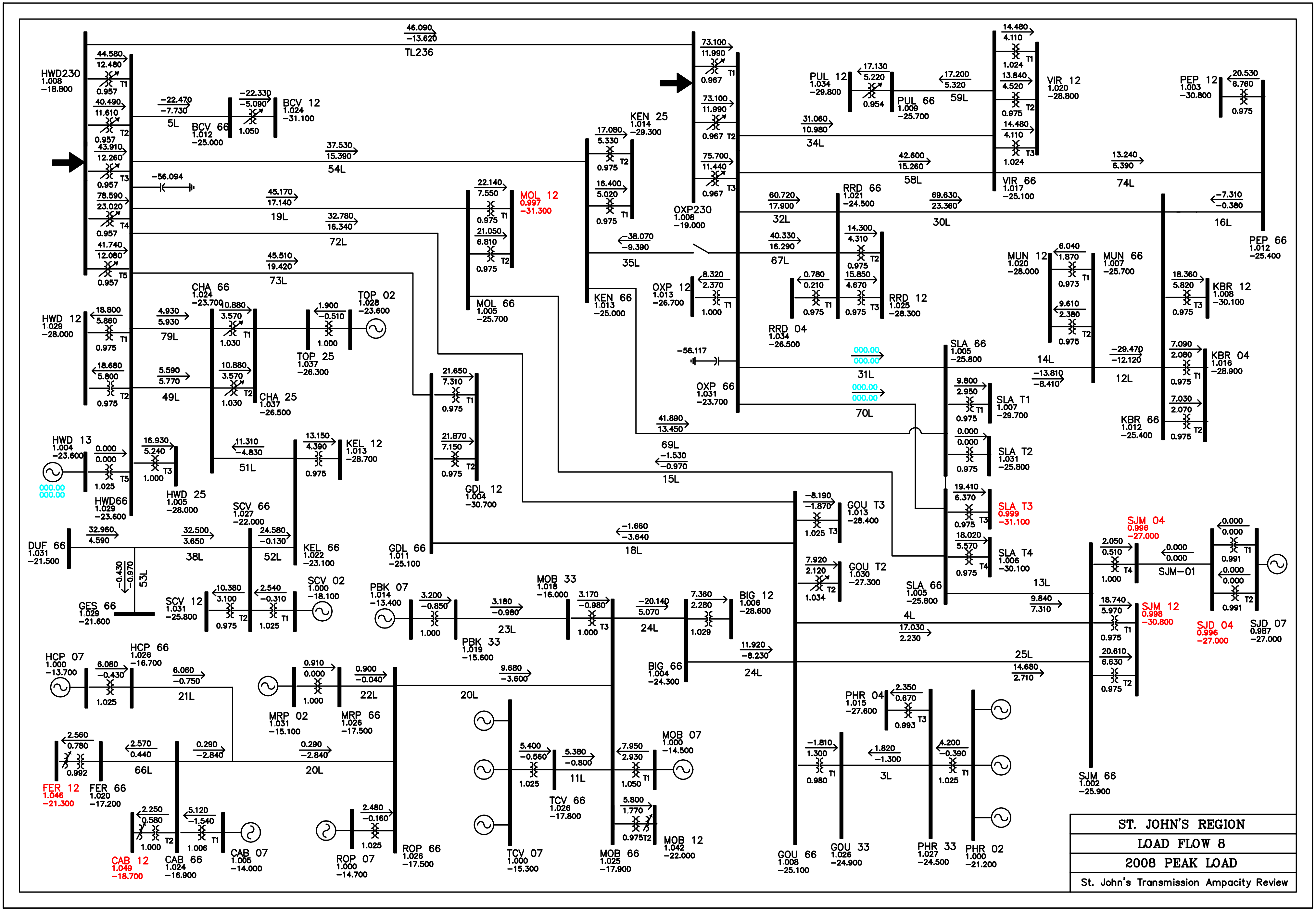


ST. JOHN'S REGION

LOAD FLOW 7

2008 PEAK LOAD

St. John's Transmission Ampacity Review

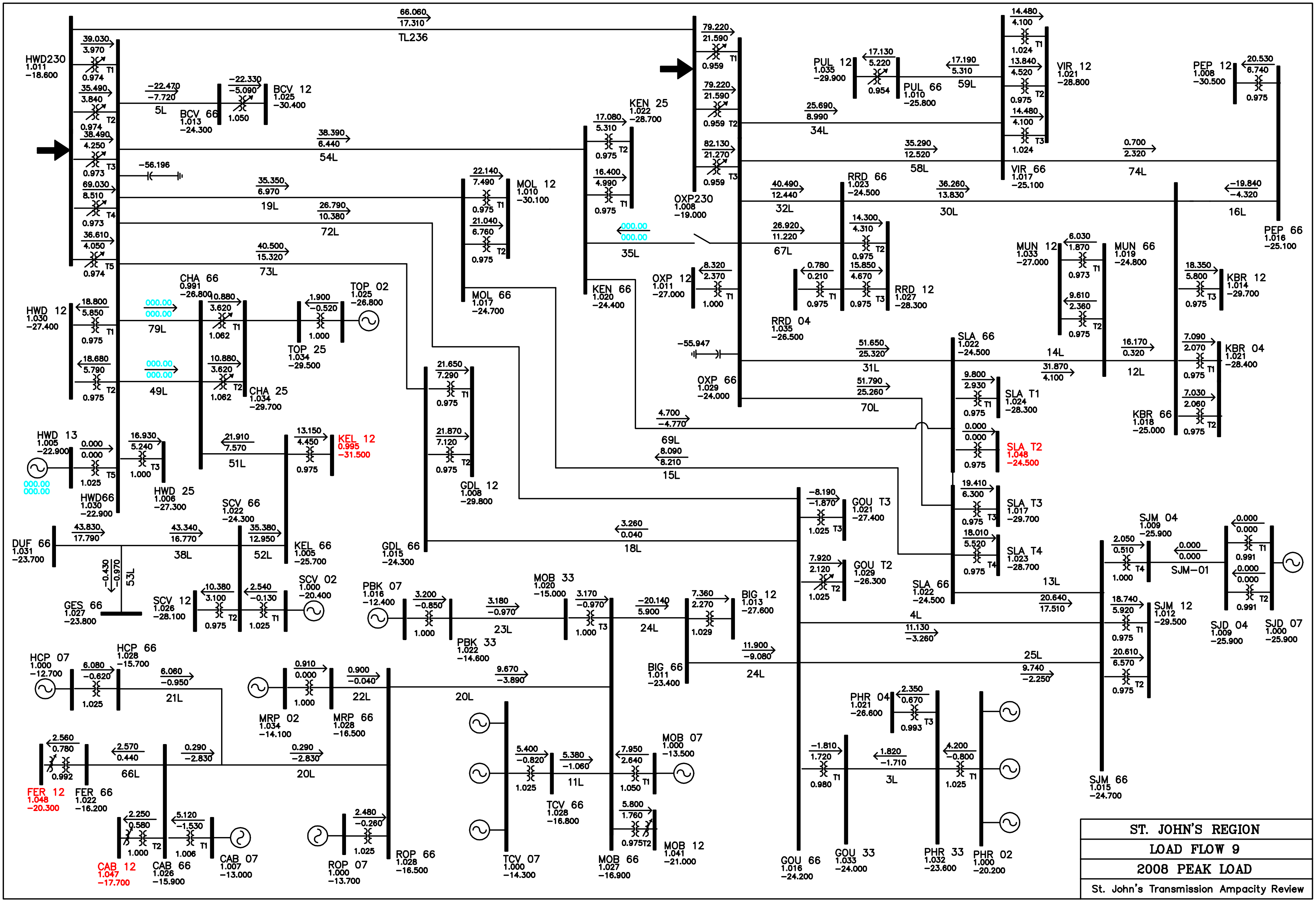


ST. JOHN'S REGION

LOAD FLOW 8

2008 PEAK LOAD

St. John's Transmission Ampacity Review



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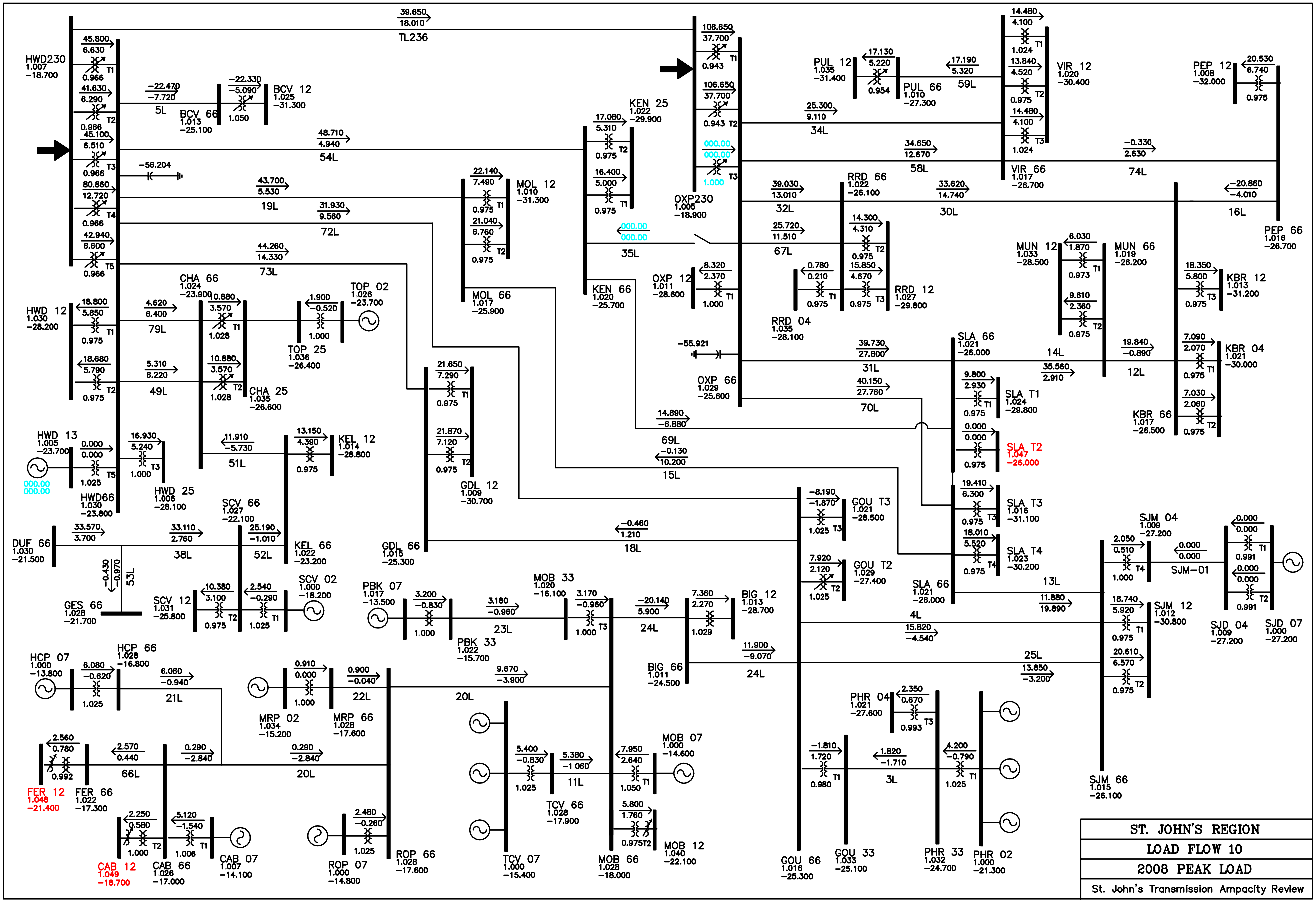
LOAD FLOW 9
2008 PEAK LOAD
St. John's Transmission Ampacity Review

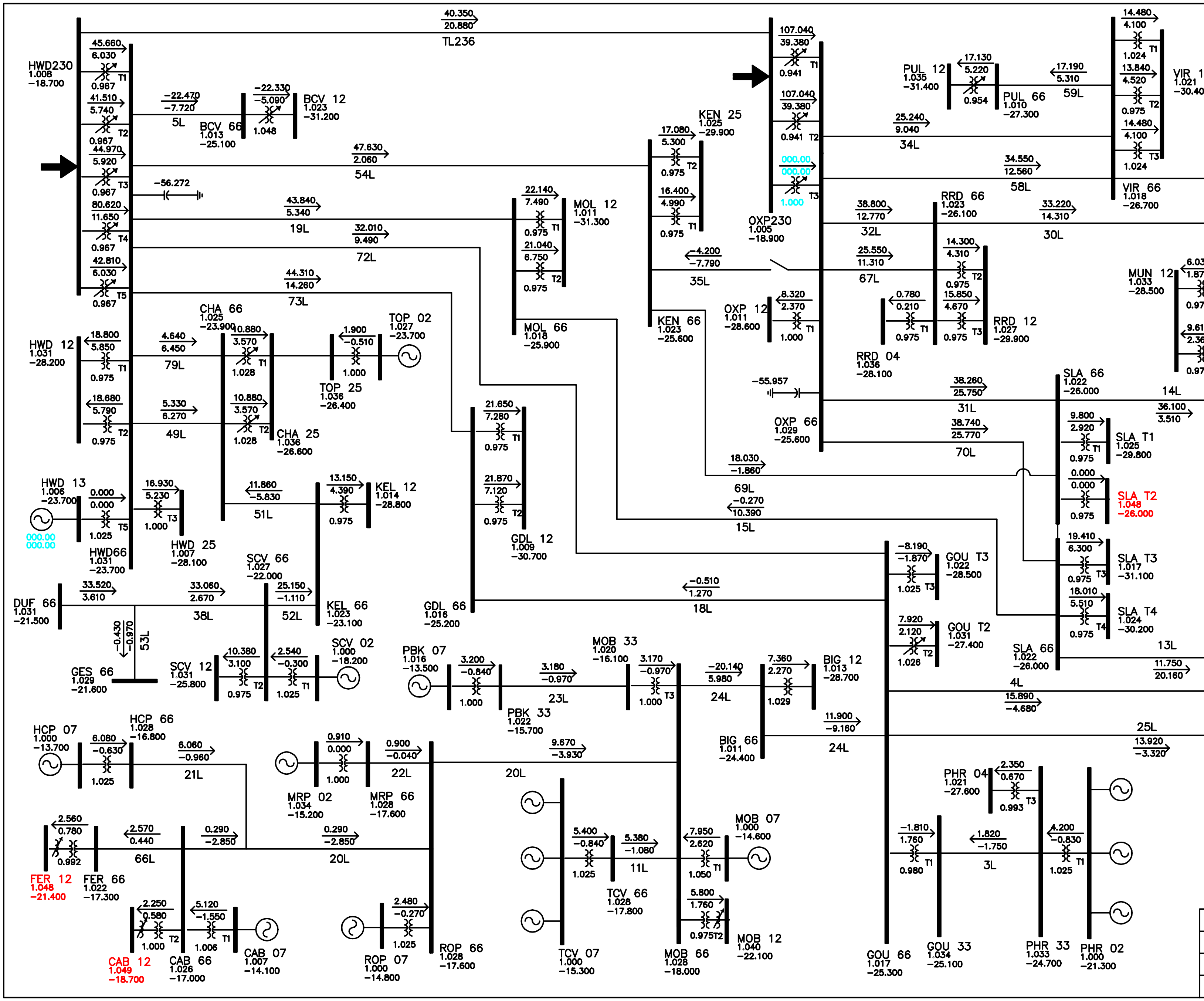


ST. JOHN'S REGION

LOAD FLOW 10

2008 PEAK LOAD

St. John's Transmission Ampacity Review

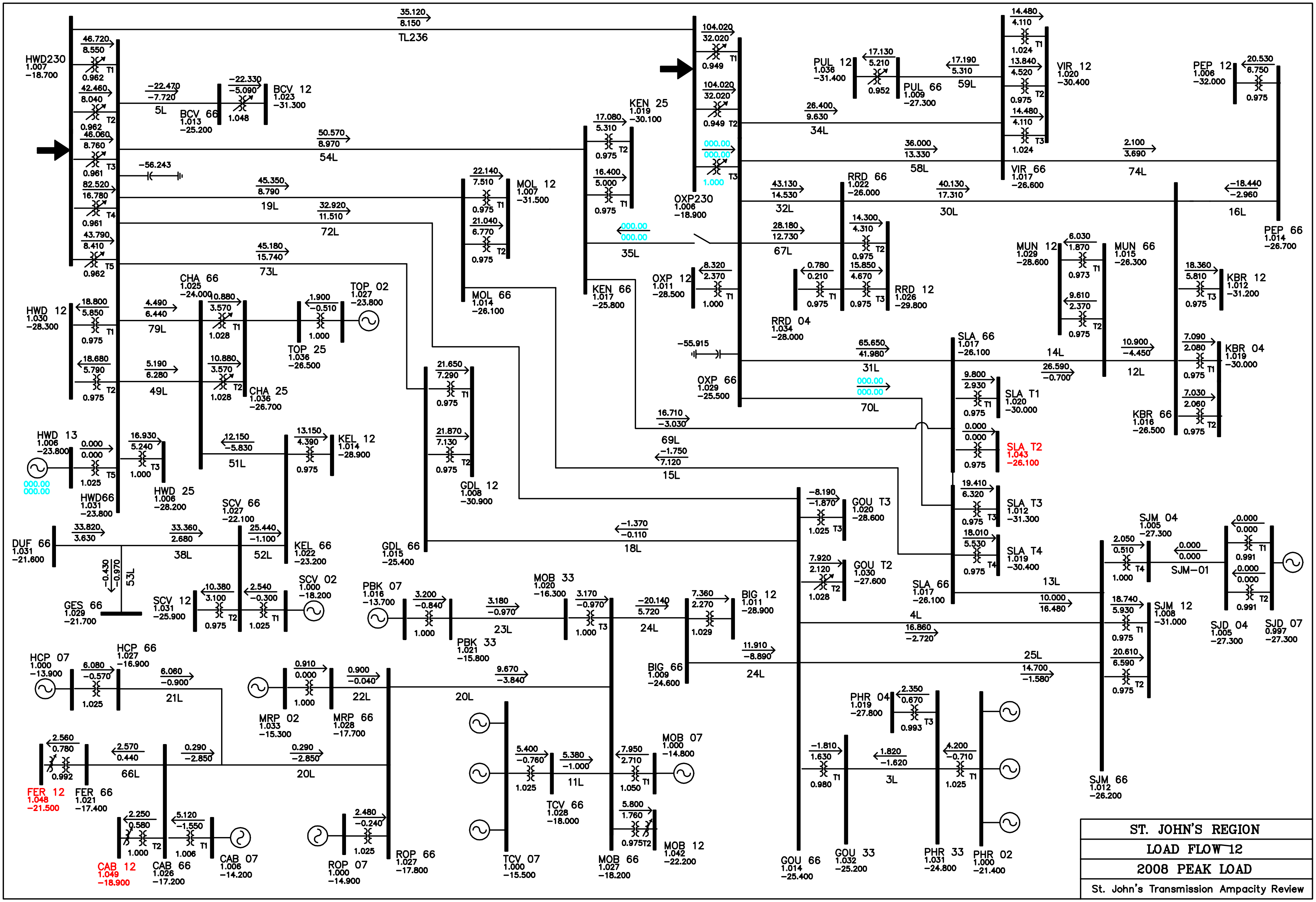


ST. JOHN'S REGION

LOAD FLOW 11

2008 PEAK LOAD

St. John's Transmission Ampacity Review



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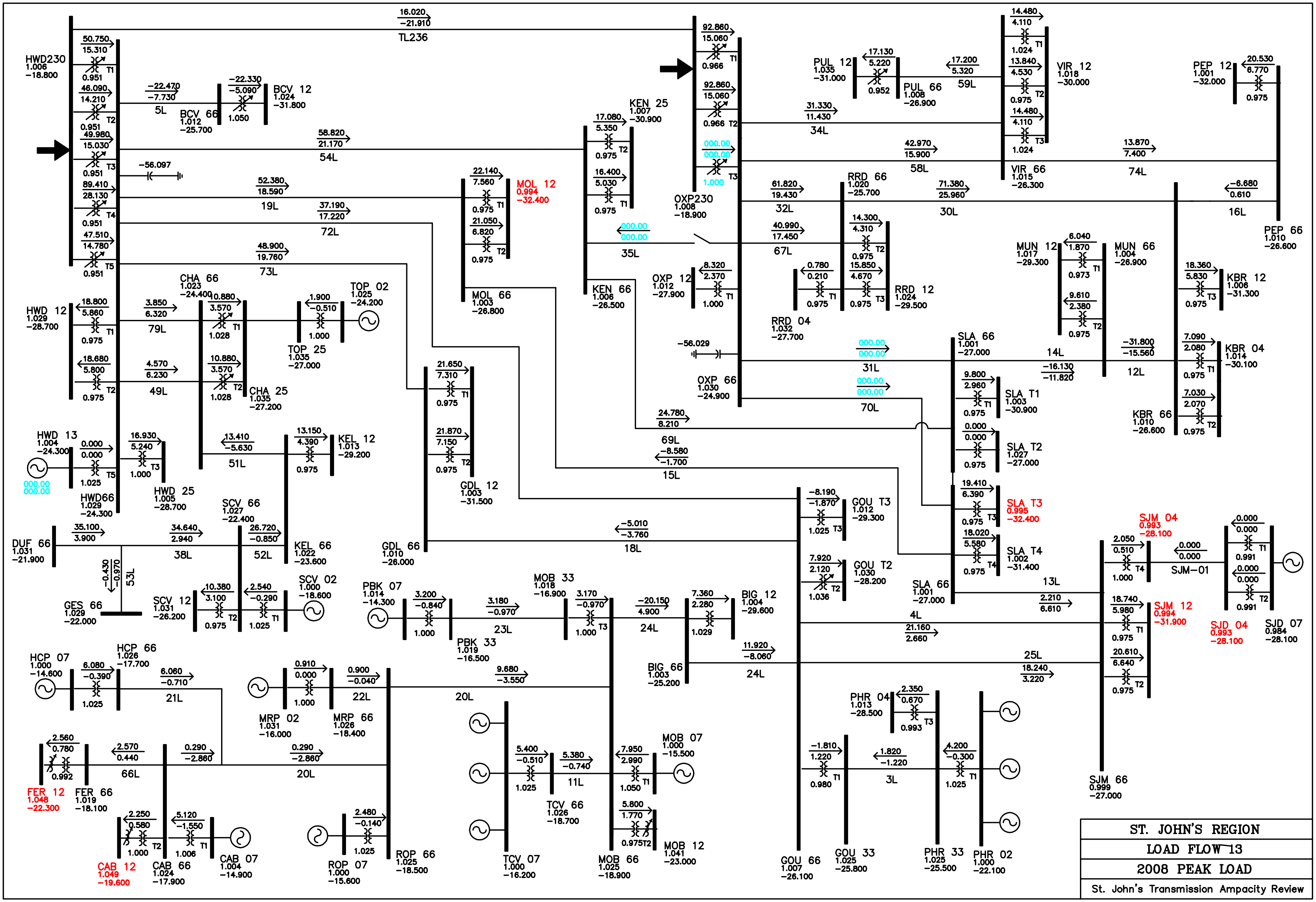
LOAD FLOW 12
2008 PEAK LOAD
St. John's Transmission Ampacity Review



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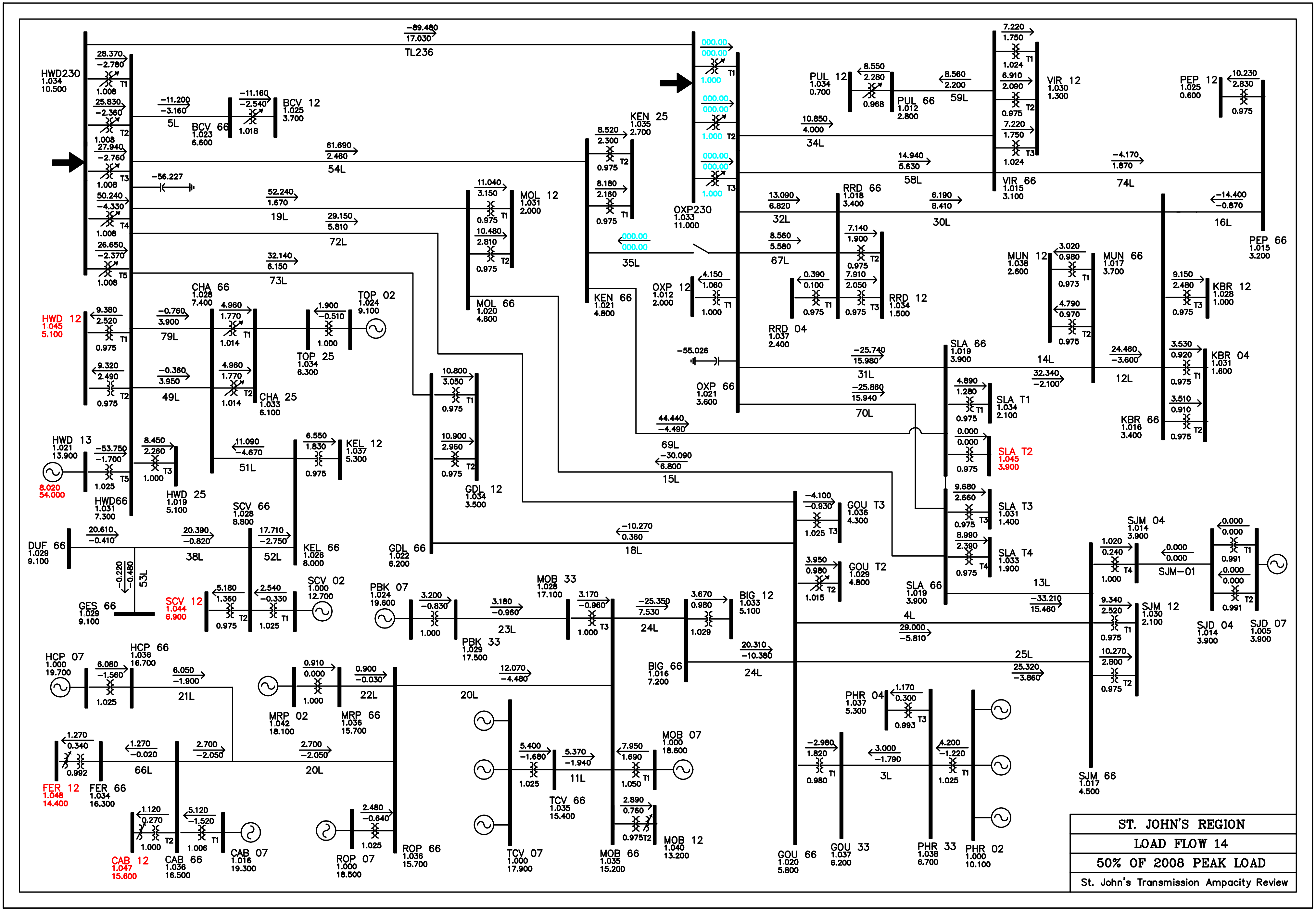
LOAD FLOW 13
2008 PEAK LOAD
St. John's Transmission Ampacity Review

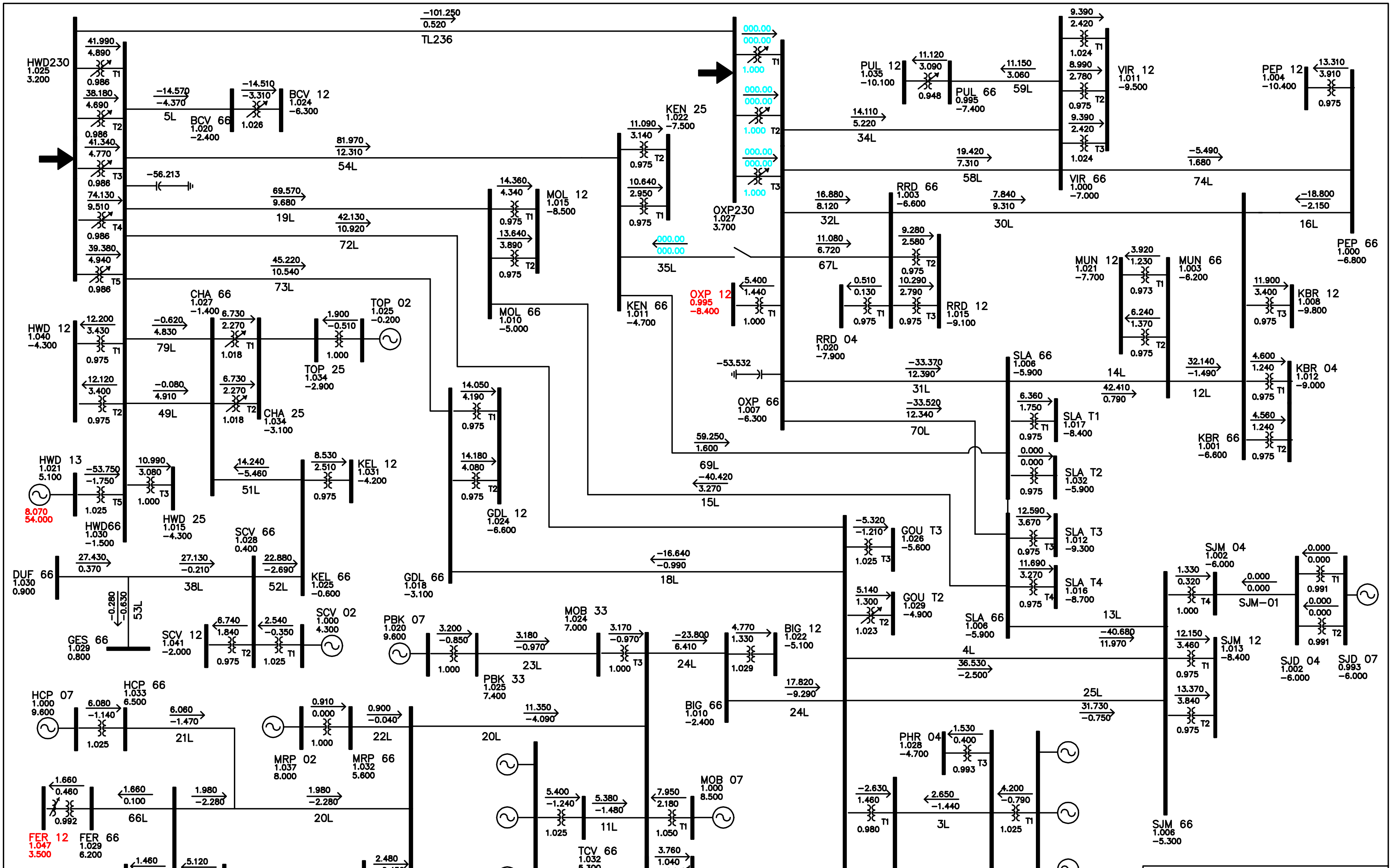


ST. JOHN'S REGION

LOAD FLOW 14

50% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

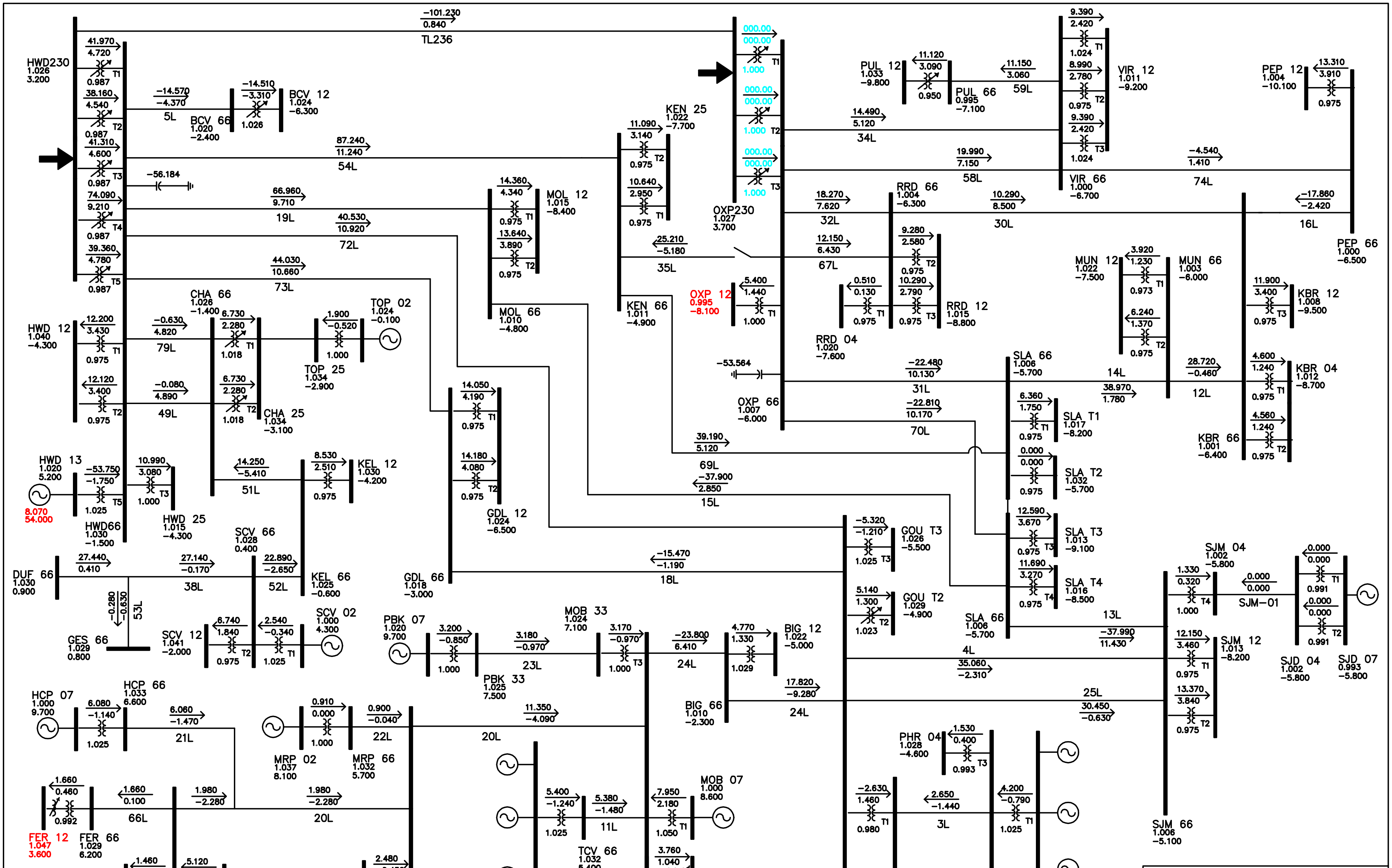


ST. JOHN'S REGION

LOAD FLOW 15

65% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

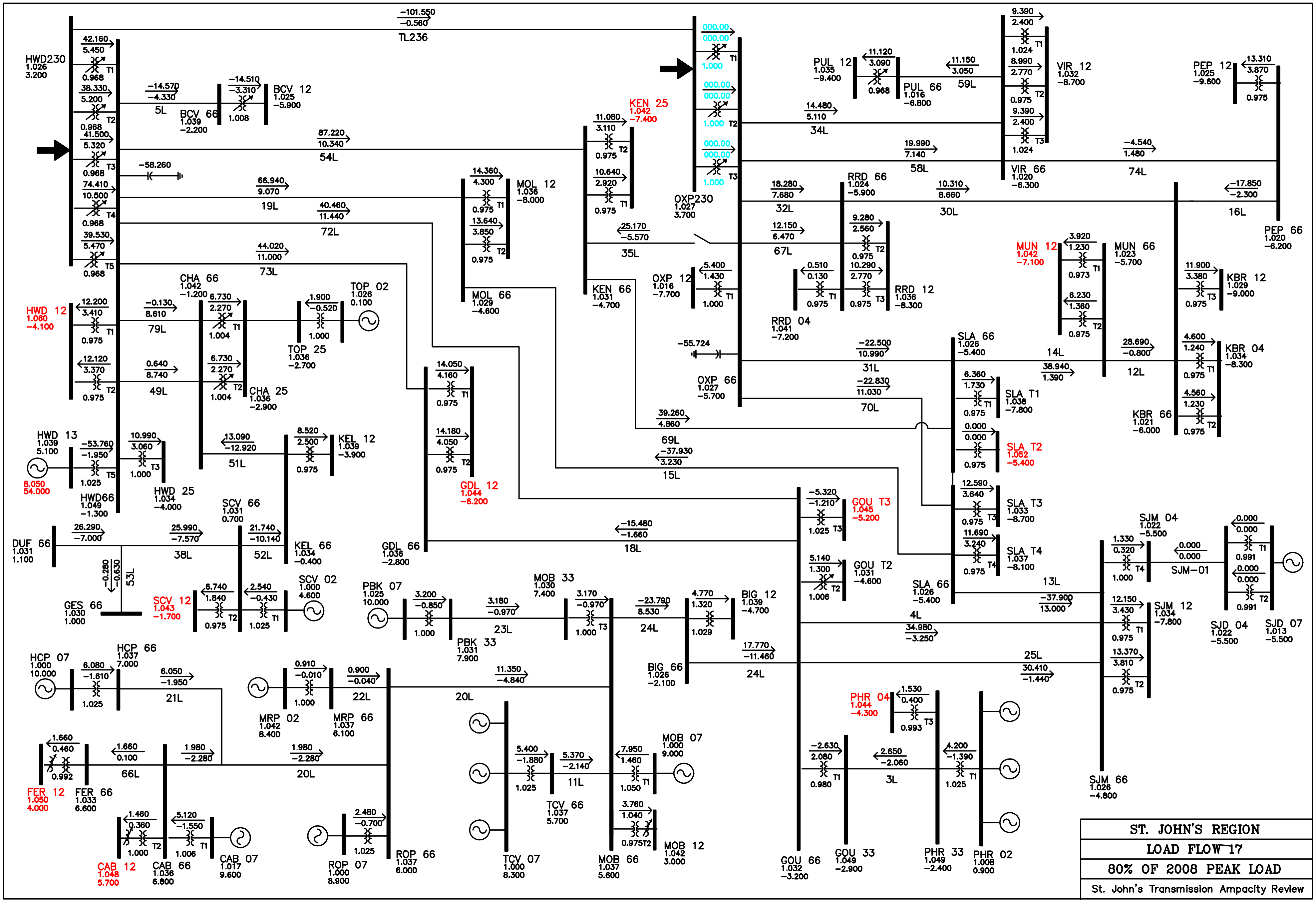


ST. JOHN'S REGION

LOAD FLOW 16

65% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

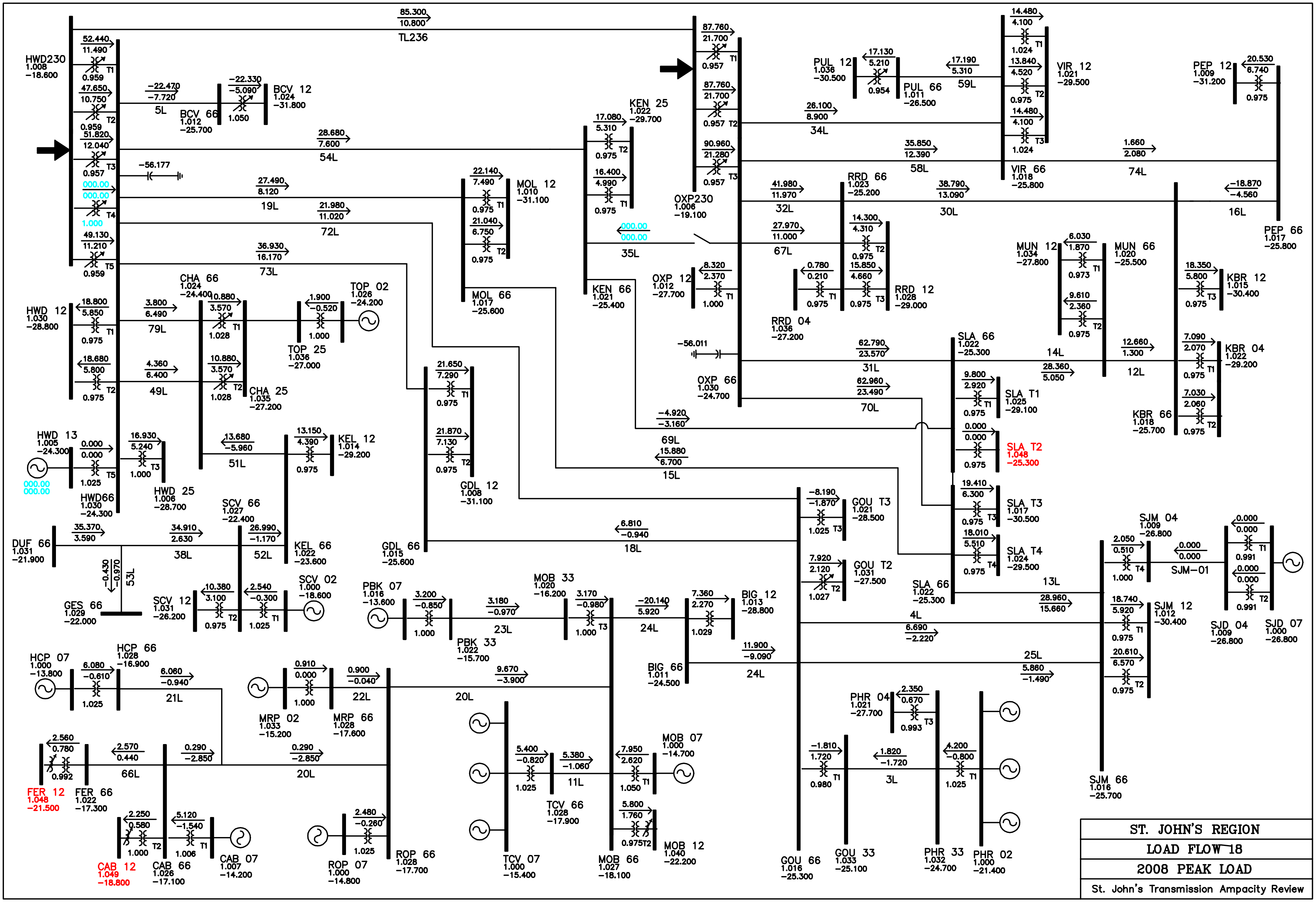


ST. JOHN'S REGION

LOAD FLOW 17

80% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

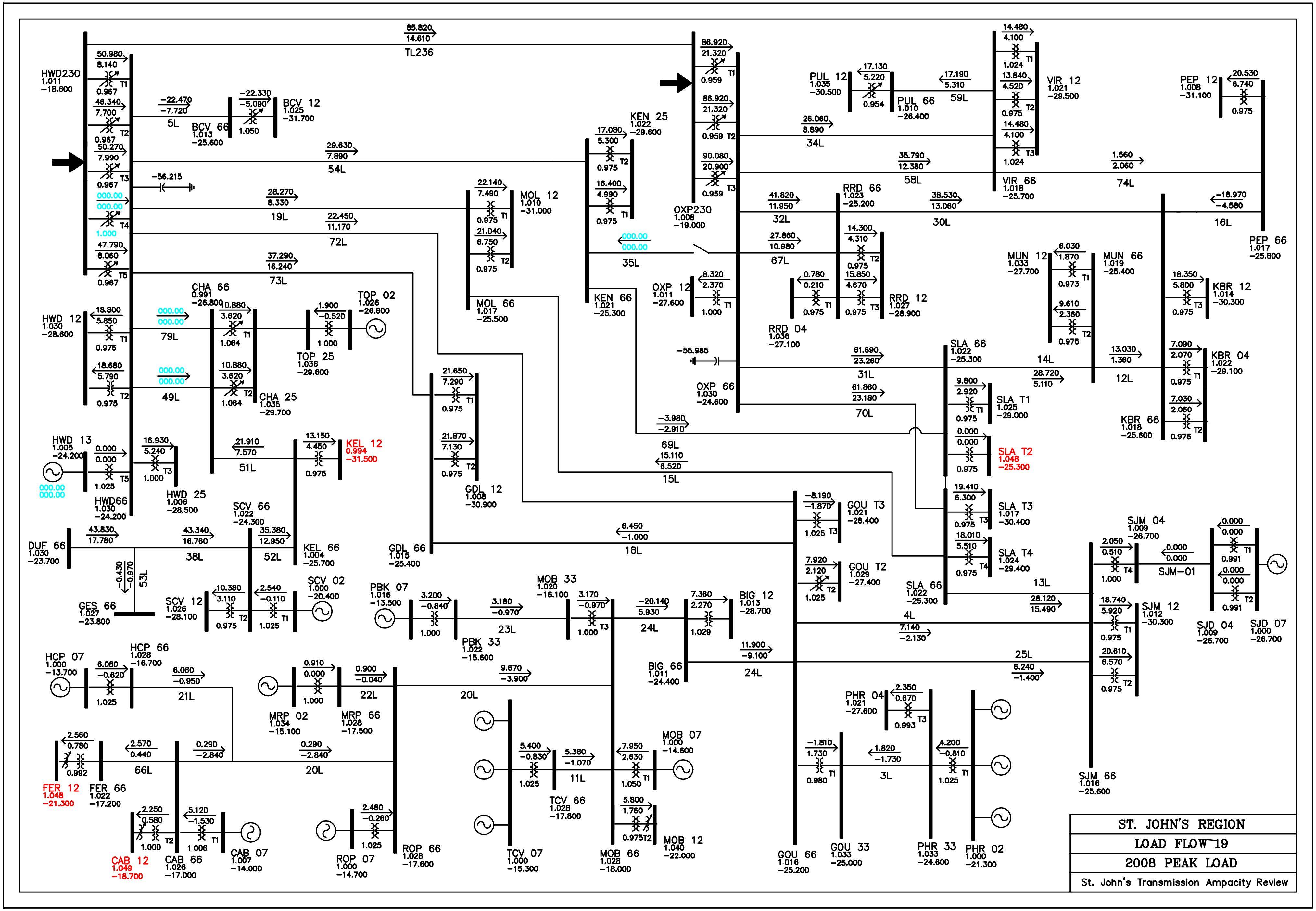


ST. JOHN'S REGION

LOAD FLOW 18

2008 PEAK LOAD

St. John's Transmission Ampacity Review

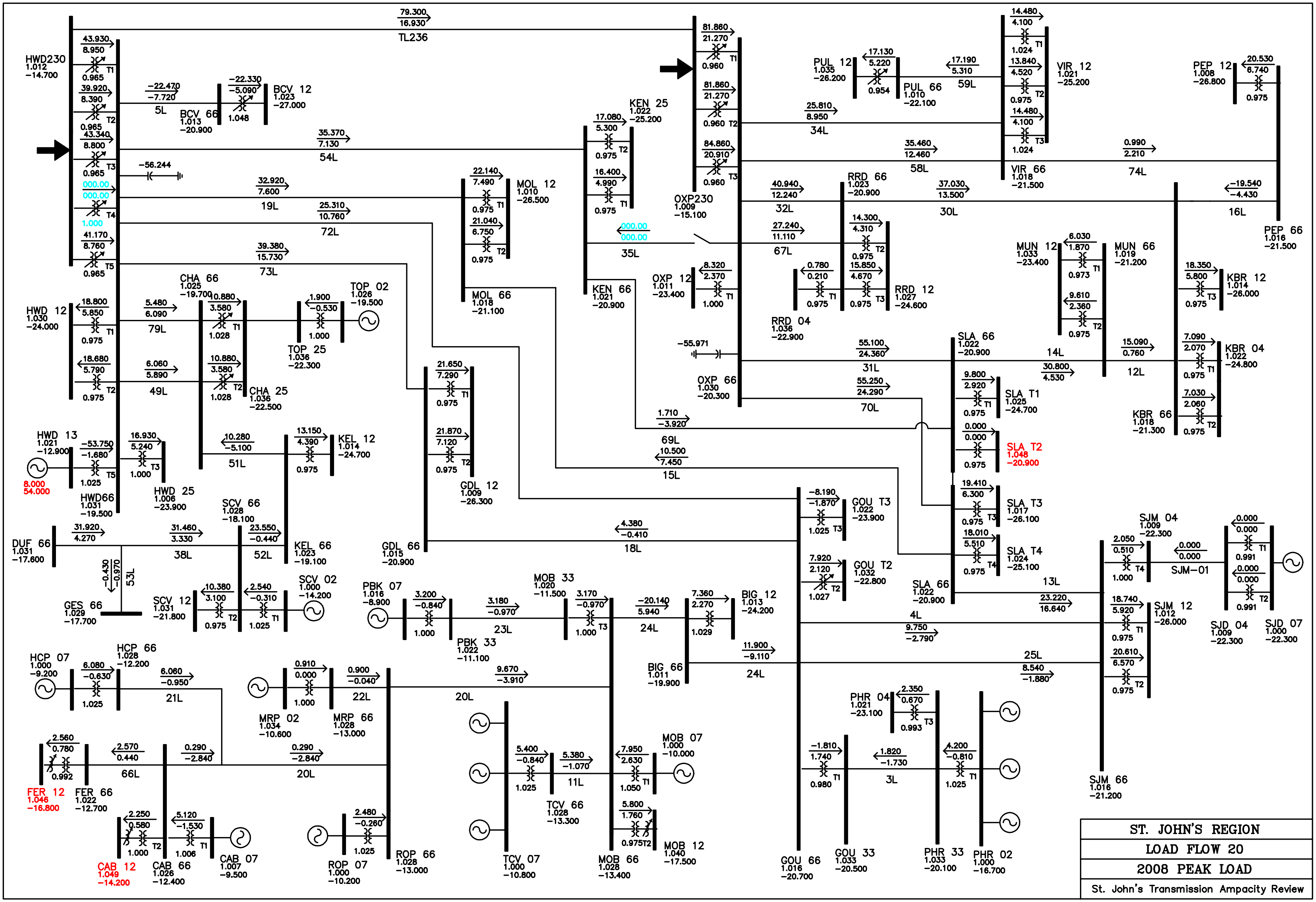


ST. JOHN'S REGION

LOAD FLOW 19

2008 PEAK LOAD

St. John's Transmission Ampacity Review

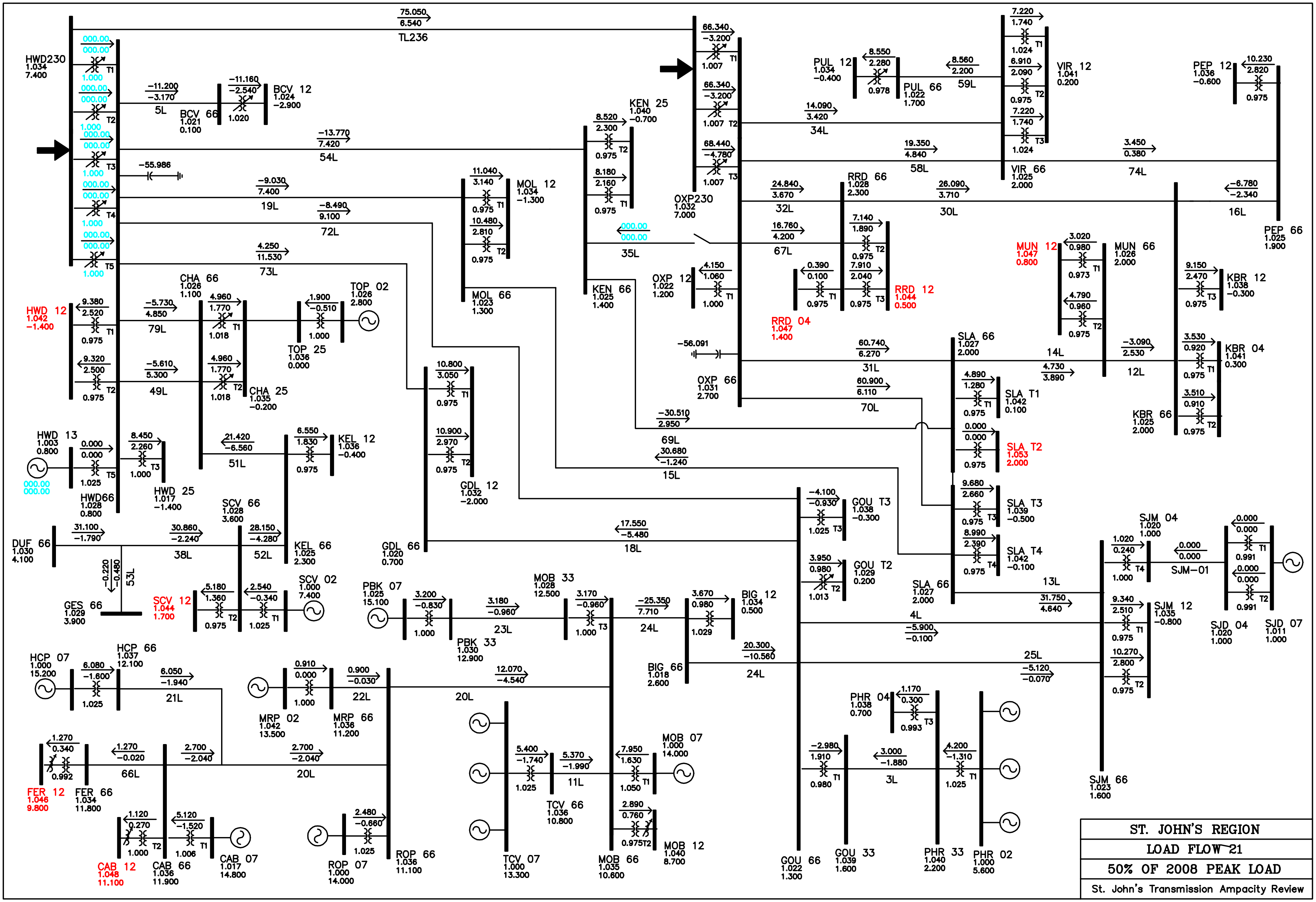


ST. JOHN'S REGION

LOAD FLOW 20

2008 PEAK LOAD

St. John's Transmission Ampacity Review

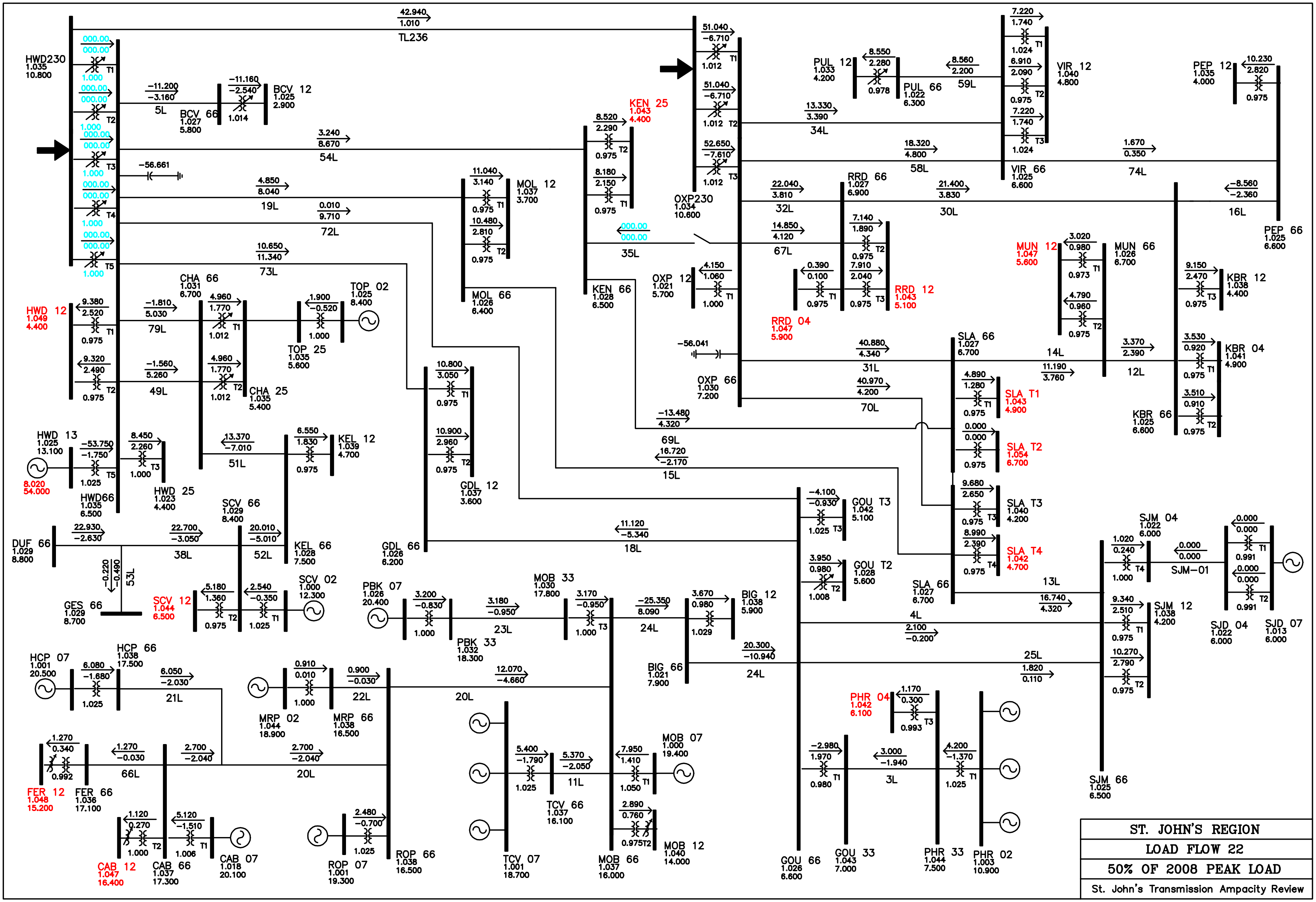


ST. JOHN'S REGION

LOAD FLOW -21

50% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

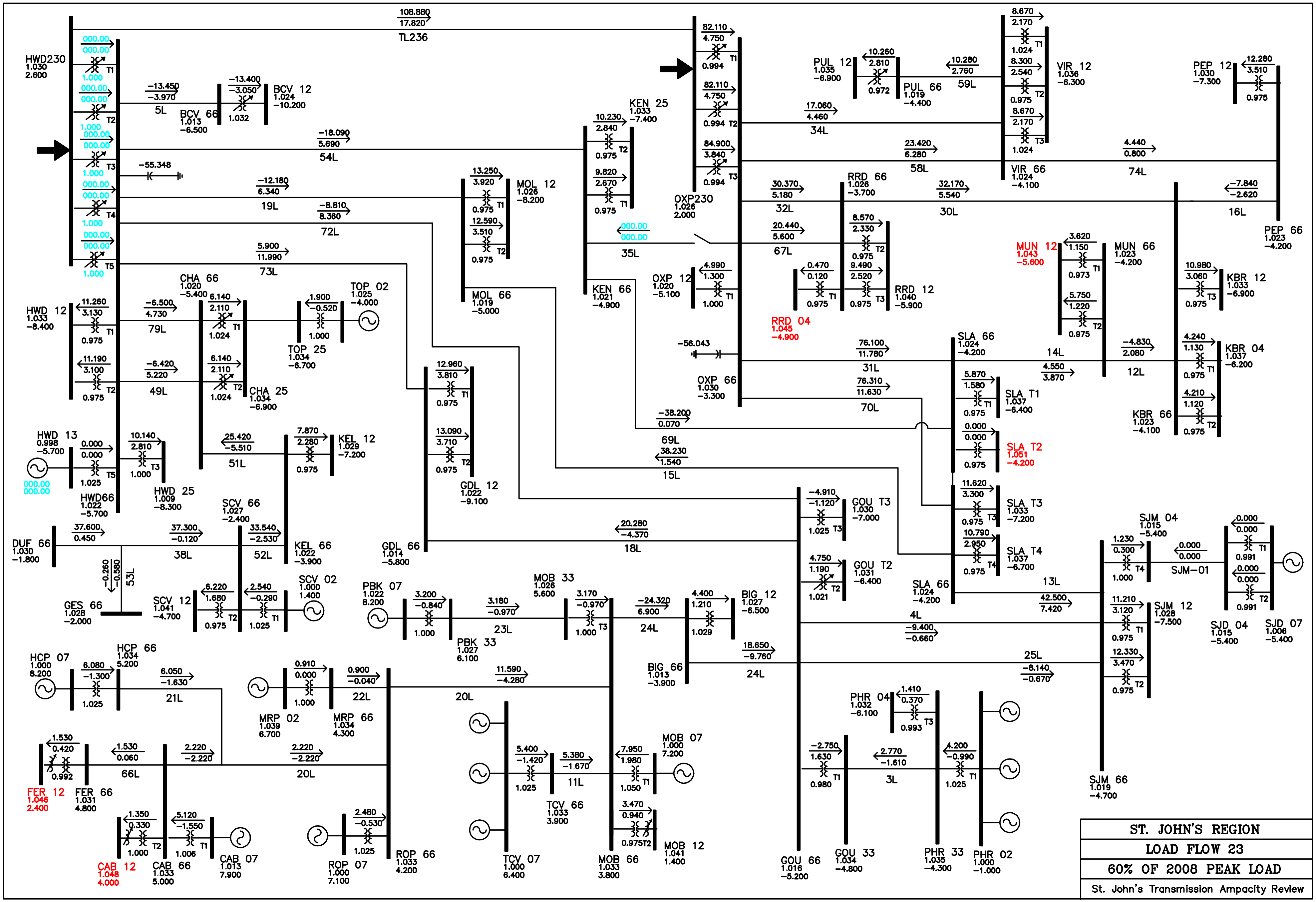


ST. JOHN'S REGION

LOAD FLOW 22

50% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

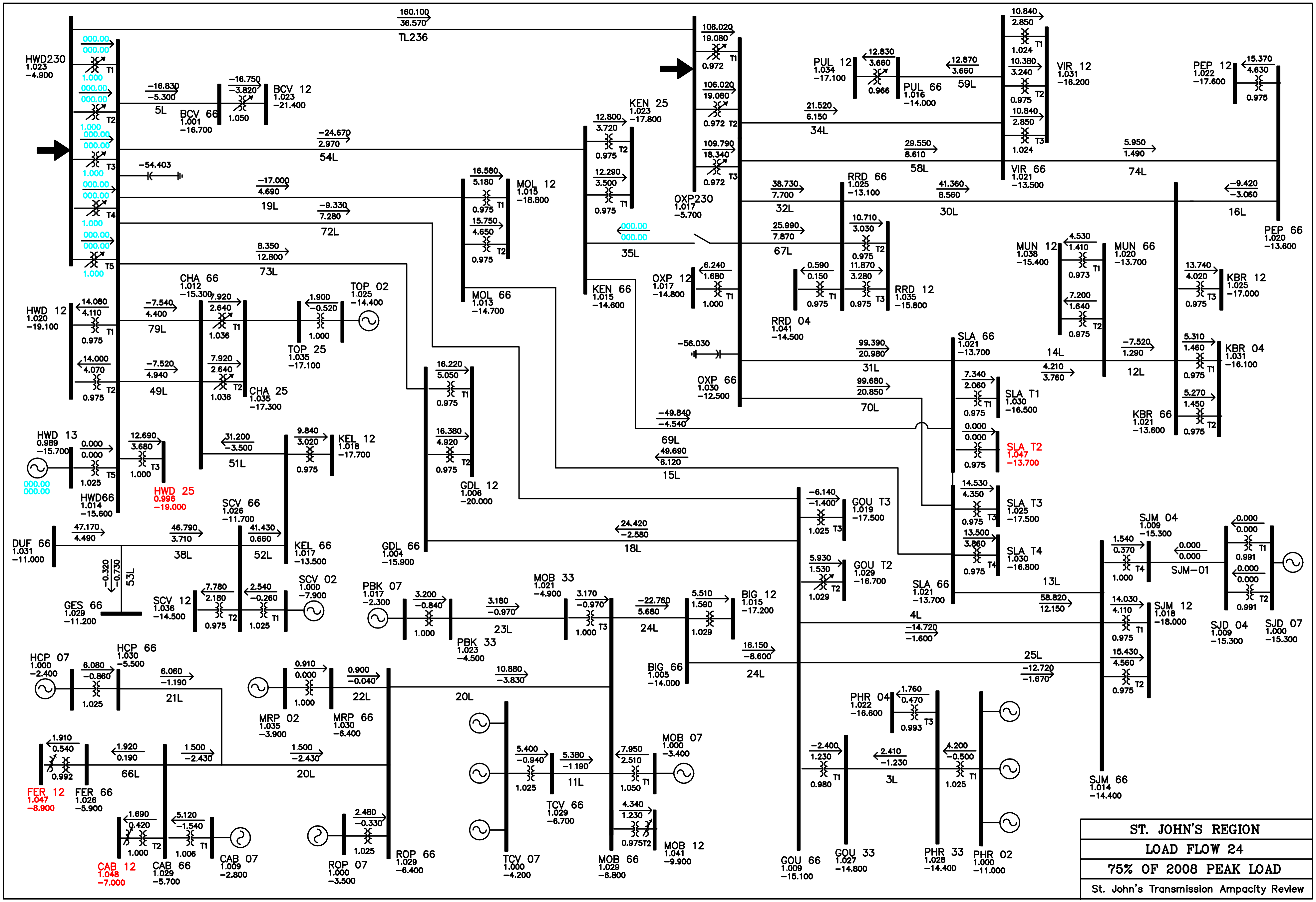


ST. JOHN'S REGION

LOAD FLOW 23

60% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

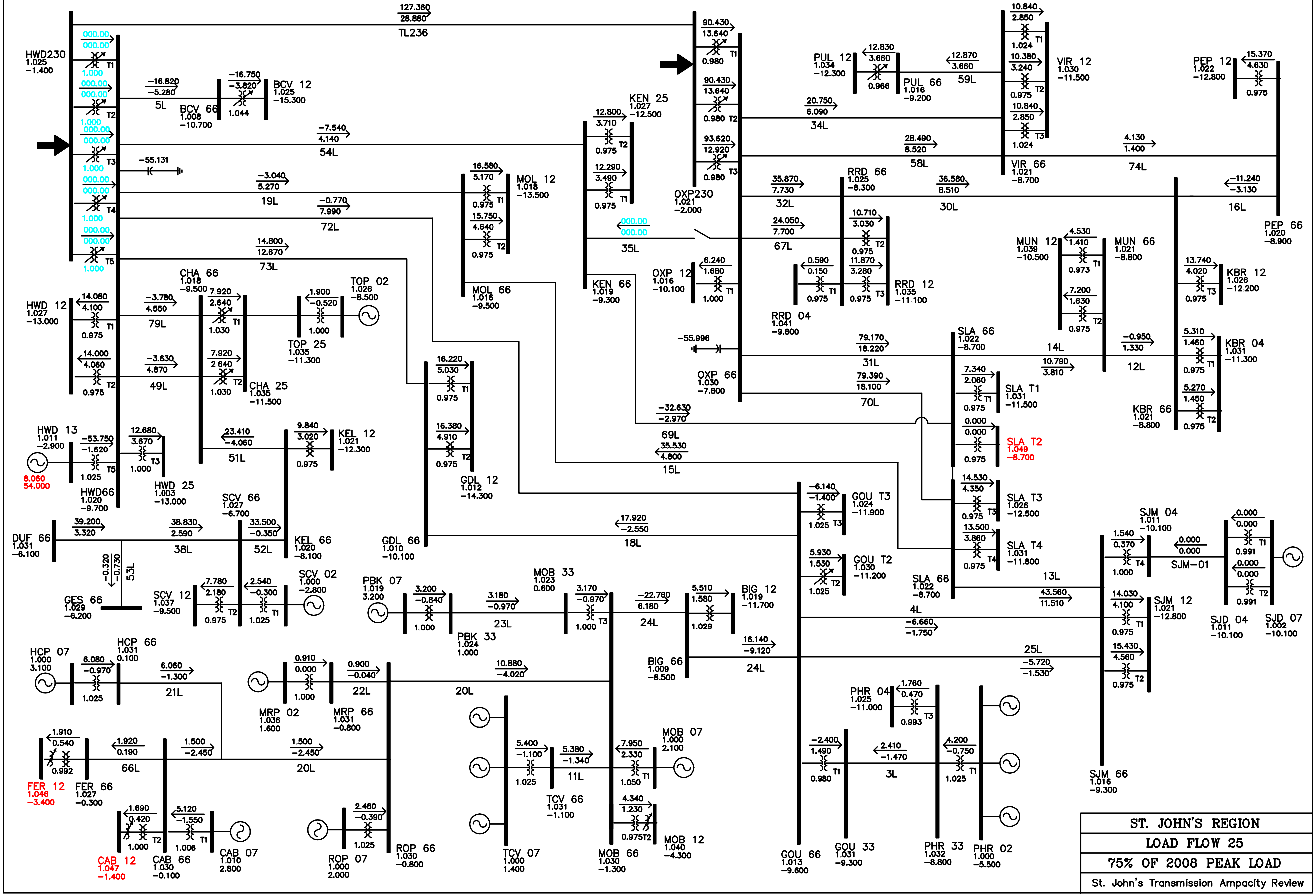


ST. JOHN'S REGION

LOAD FLOW 24

75% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

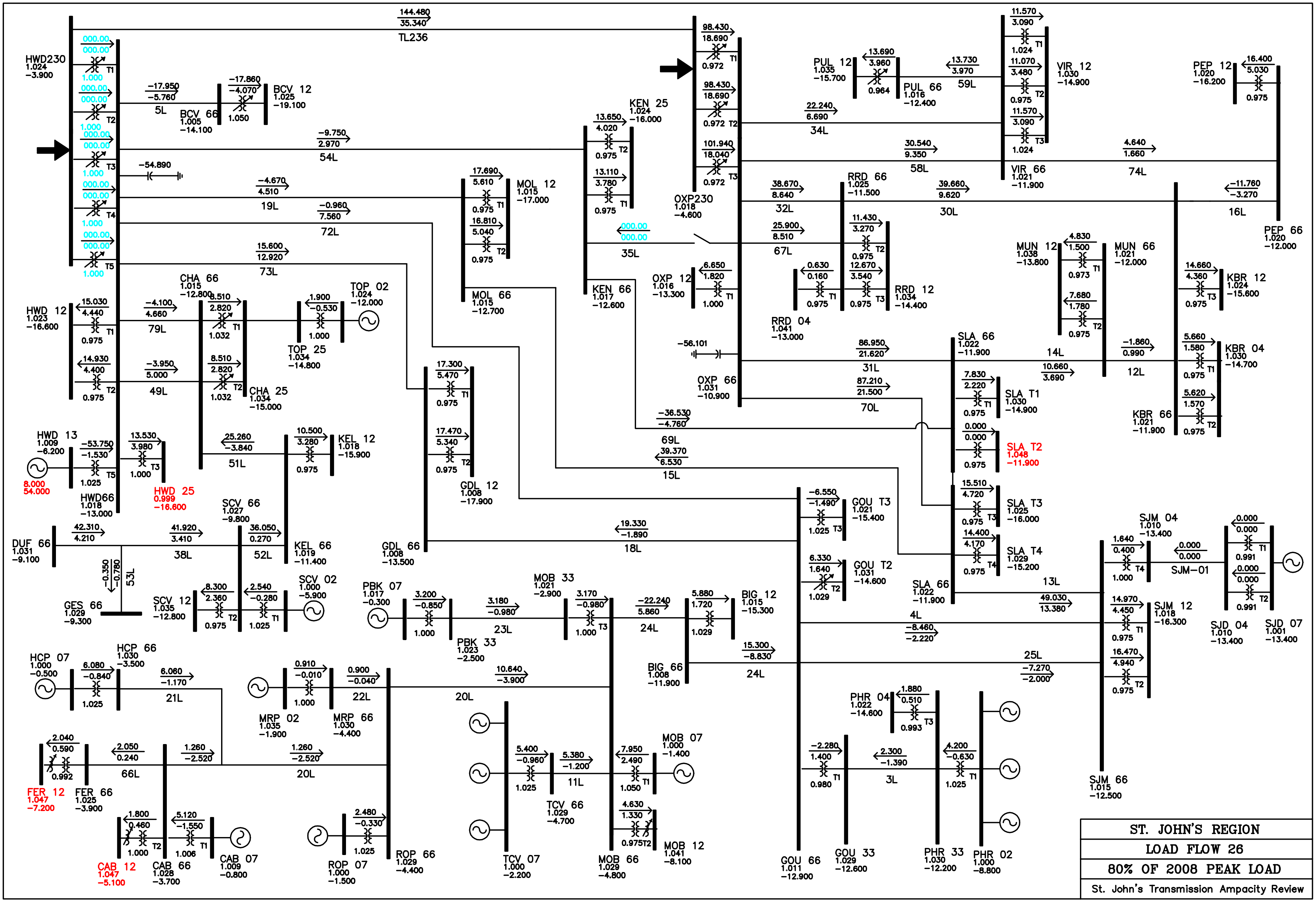


ST. JOHN'S REGION

LOAD FLOW 25

75% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

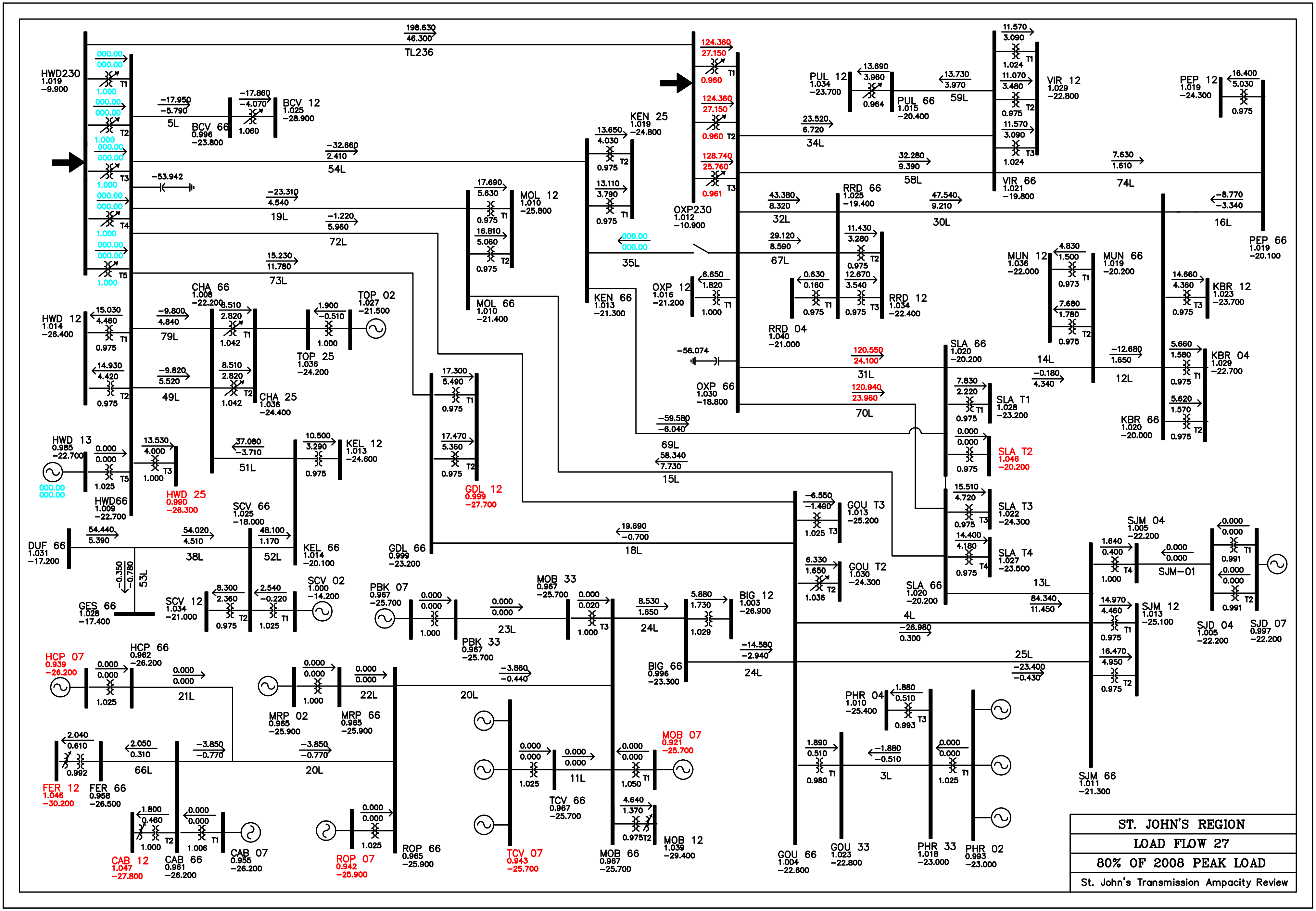


ST. JOHN'S REGION

LOAD FLOW 26

80% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

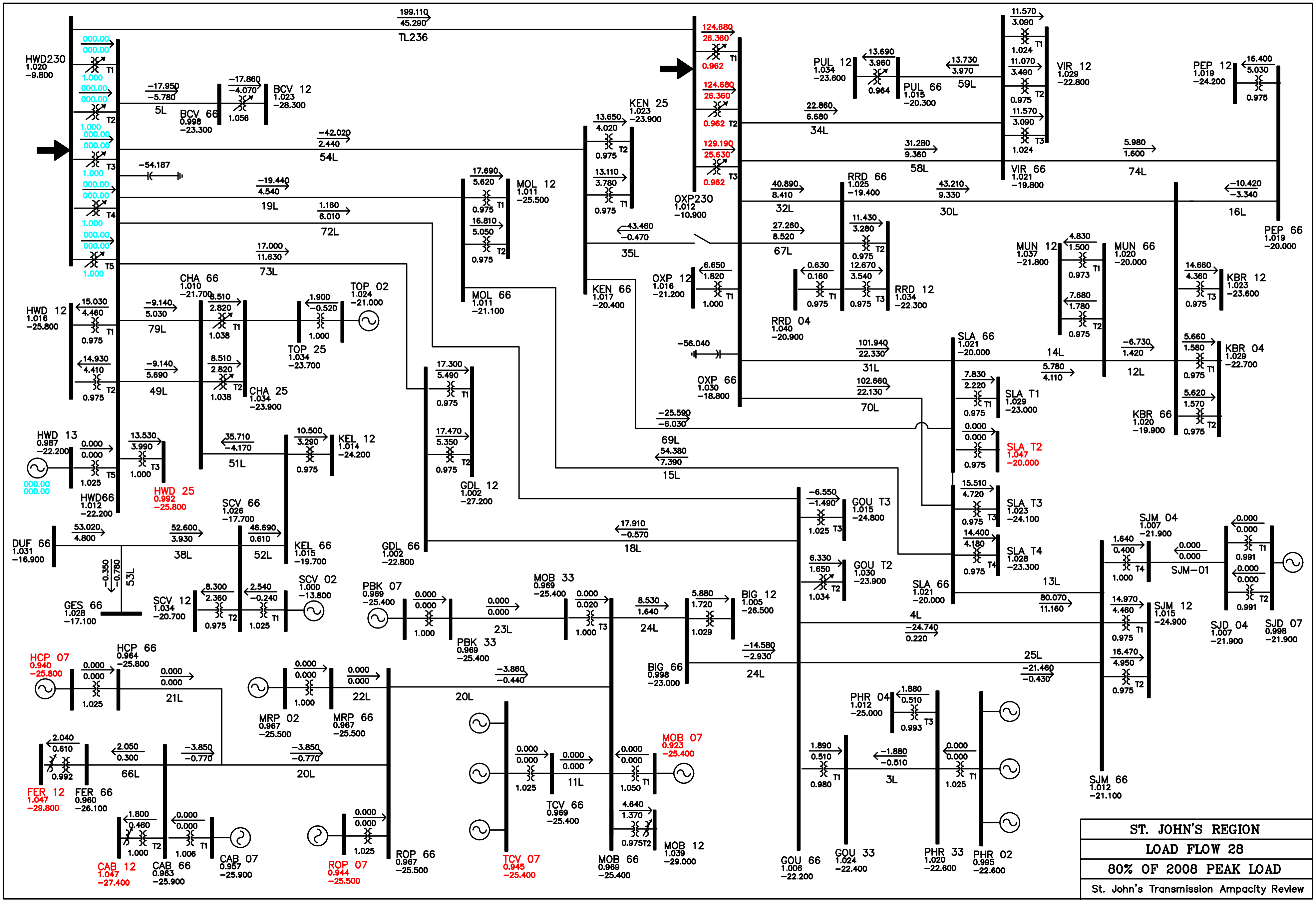


ST. JOHN'S REGION

LOAD FLOW 27

80% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

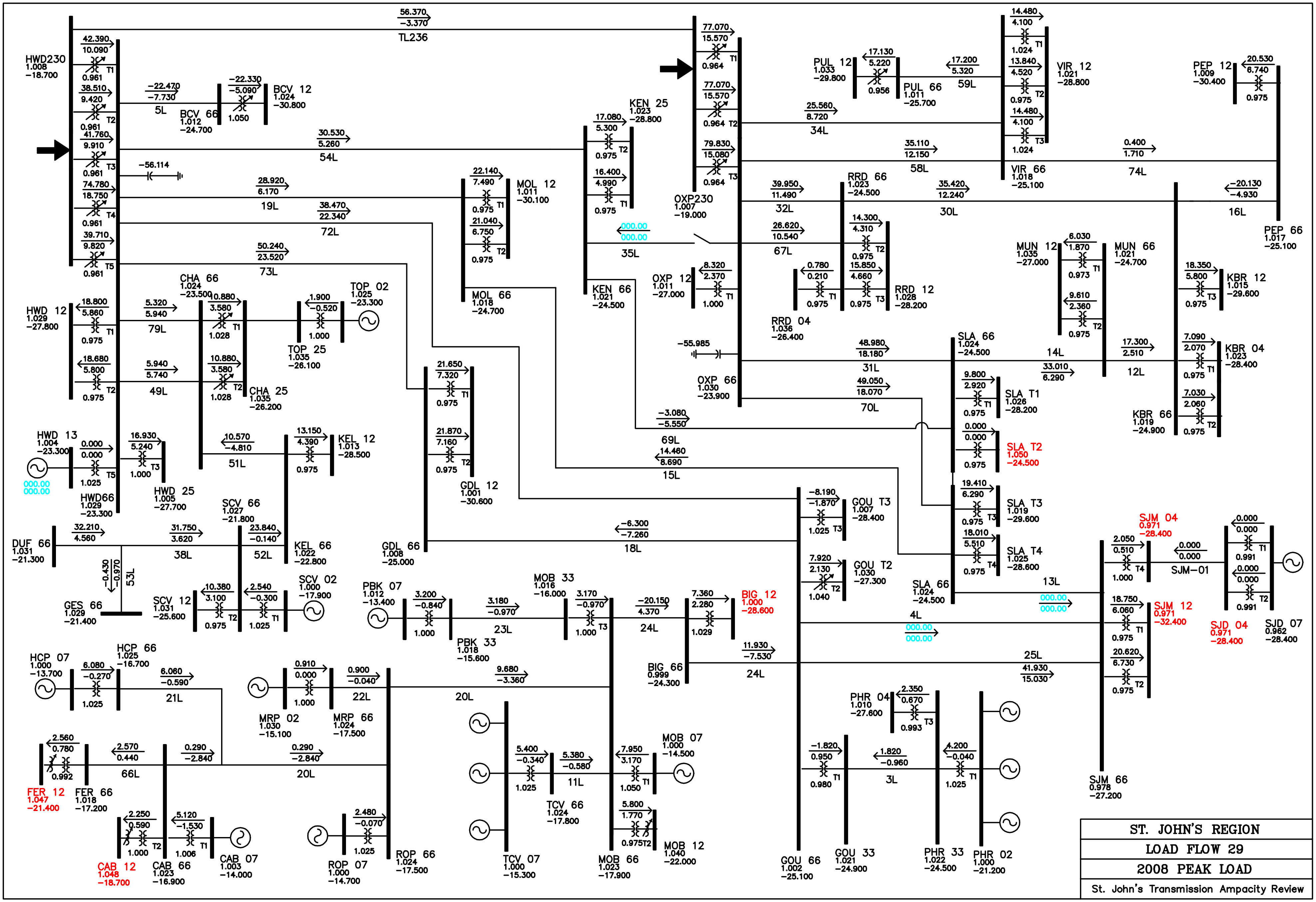


ST. JOHN'S REGION

LOAD FLOW 28

80% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION

LOAD FLOW 29

2008 PEAK LOAD

St. John's Transmission Ampacity Review

Newfoundland Power
2004 Capital Budget Application
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Information Technology Strategy 2004 - 2008

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Prefiled Evidence: Ludlow / Delaney

Prefiled Evidence: Mulcahy / Collins

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Expenditure Details, Reports and Studies

Volume IV
Expenditure Details, Reports and Studies

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.

NEWFOUNDLAND POWER
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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

NEWFOUNDLAND
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DISTRIBUTION FEEDER INSPECTION REPORT

Feeder #: ____________________

Date: ____________________

POLE #	STRUCTURE TYPE	PRIORITY	LOCATION	DESCRIPTION OF DEFECT	COMMENTS

Inspected By: ______________________

Page: _____ **of** _____

Distribution
Appendix 2
Attachment B

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**

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[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

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

[4] From "Cost Estimate to Install Lightning Arrestor"

[5] From "Cost Estimate to Install Lightning Arrestor"

Cost of Transformer Failures

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

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[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
Appendix 2
Attachment C

Distribution Insulator Replacement Program

Newfoundland Power Inc.
June 2003

Prepared By: Peter Feehan, P.Eng.

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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.

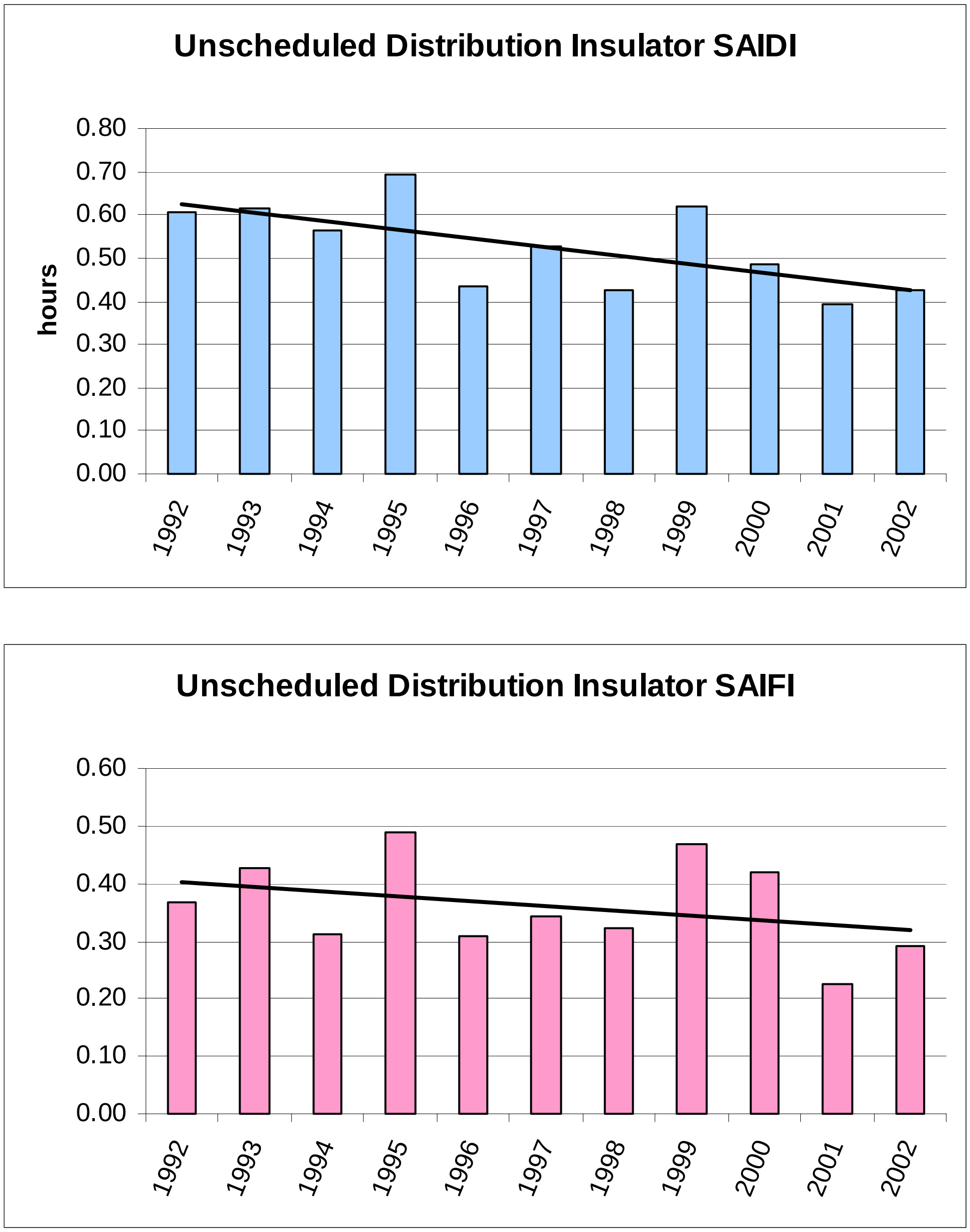

Figure 1: Insulator Related SAIFI & SAIDI

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.

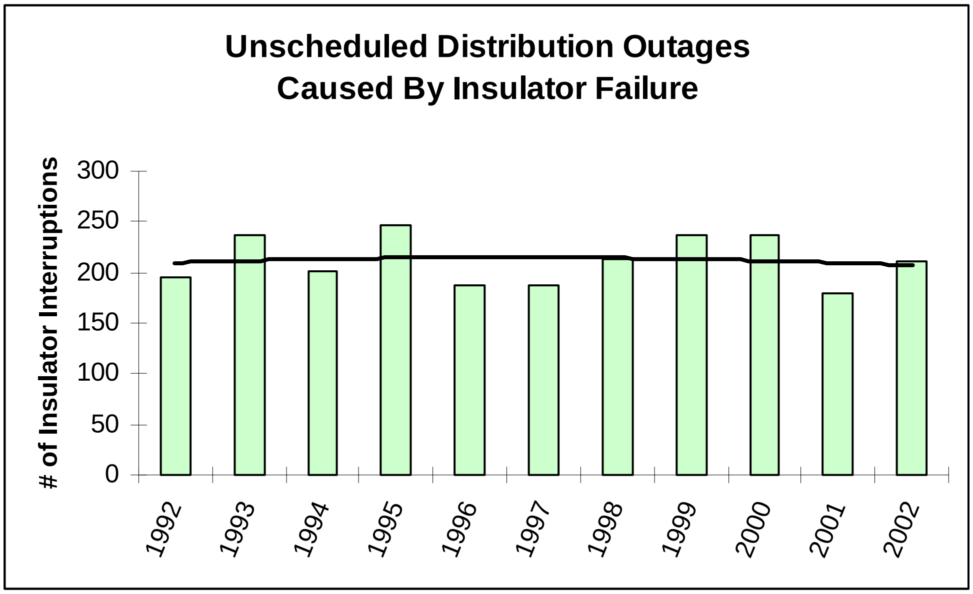

Figure 2: Number of Insulator Interruptions

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 Hazards of Faulty Insulators

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 Testing vs. Replacement

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.

Distribution
Appendix 2
Attachment D

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 x 10^{-5} at 3000 amps, 8.6 x 10^{-5} at 5000 amps to 34 x 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

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REPORT FOR THE

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A Utility's Guide to

Minimizing Pole Top Transformer Tank Failures

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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 5×10^{-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.

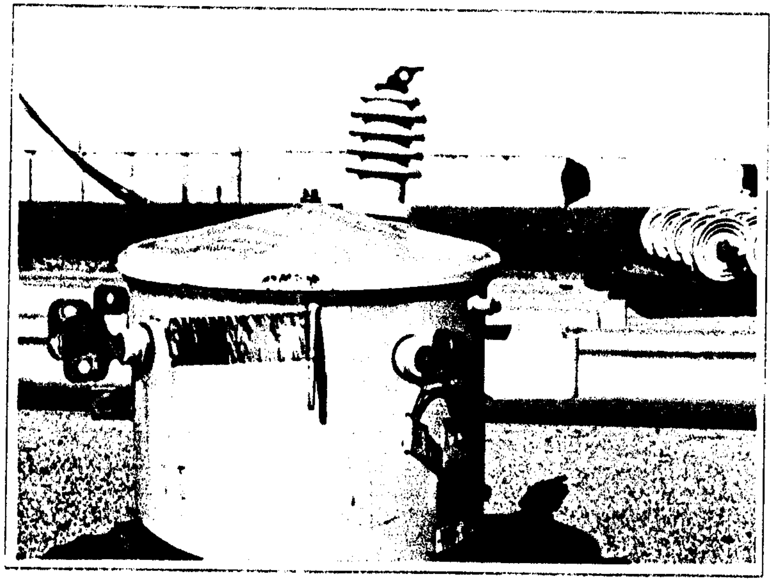

FIGURE 1

POLE TOP TRANSFORMER WITH CENTRE BOLT LID

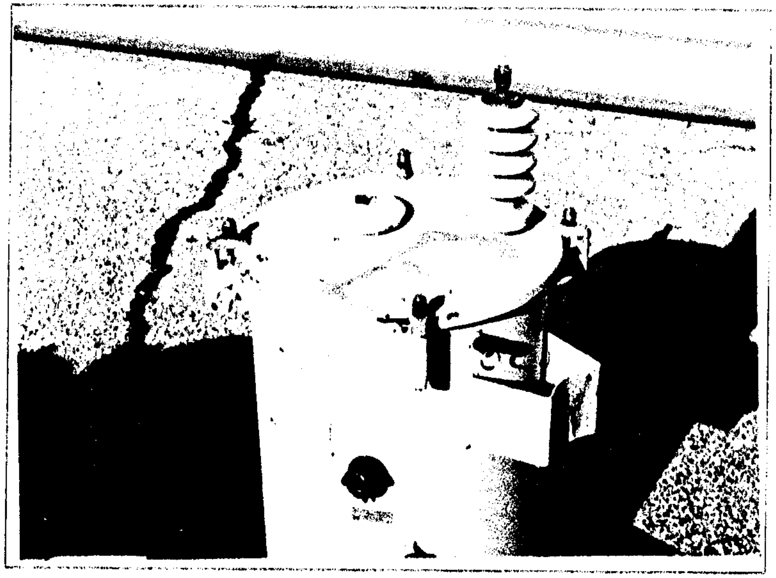

FIGURE 2

POLE TOP TRANSFORMER WITH EDGE CLAMP LID

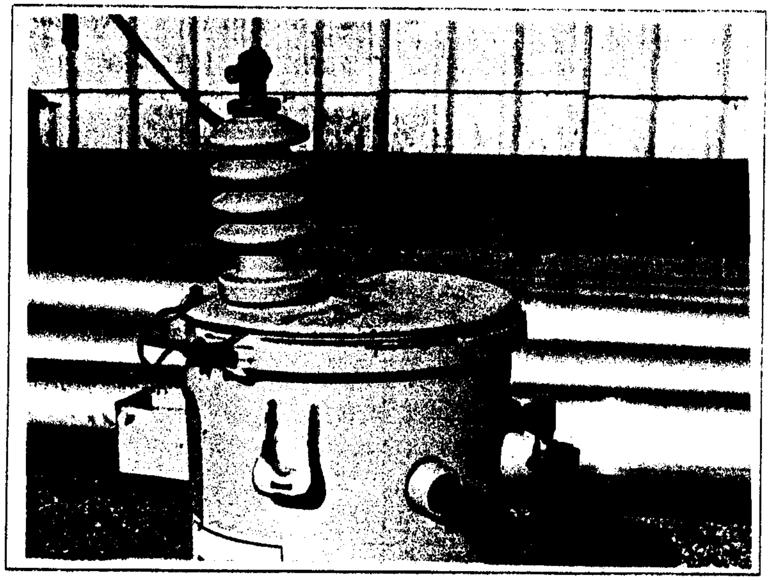

FIGURE 3

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. The 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.

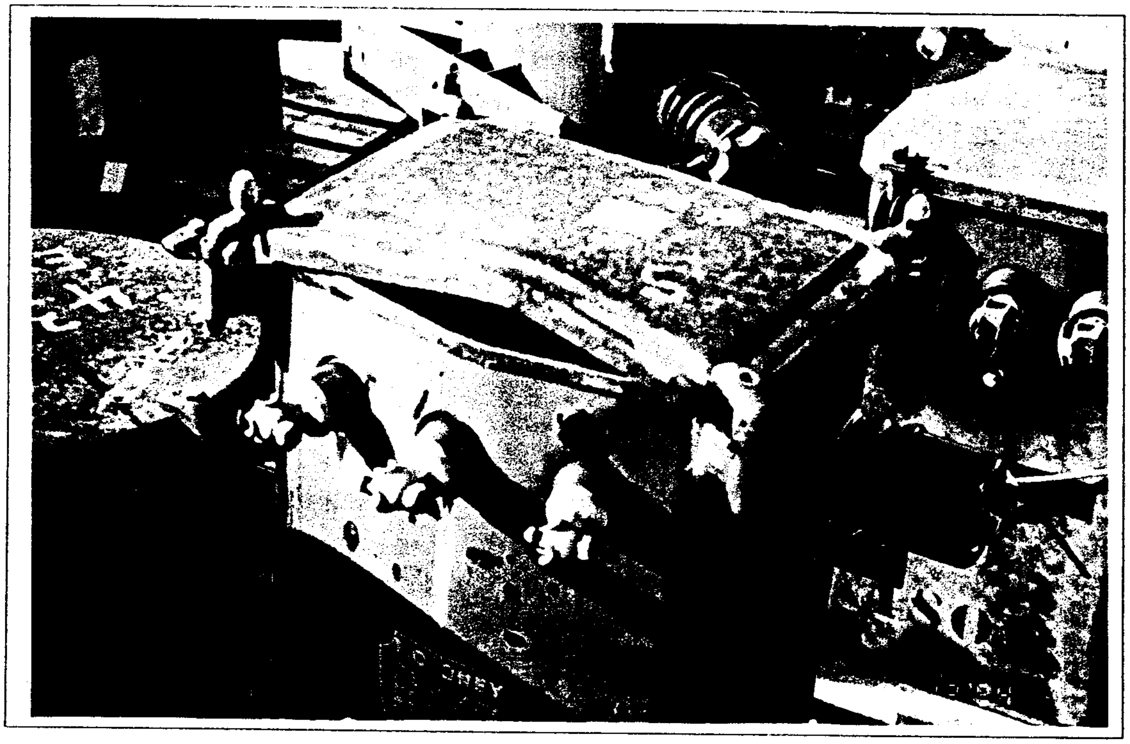

FIGURE 4

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.

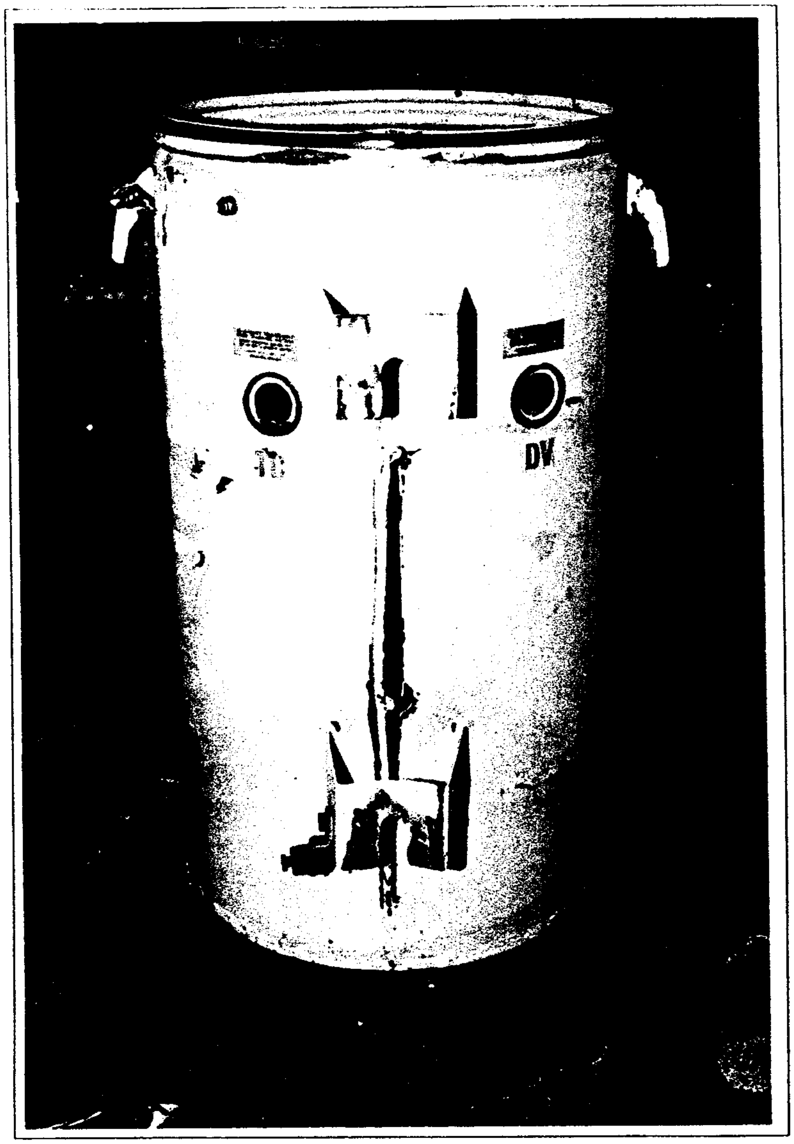

FIGURE 5

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 $8x10^{-5}$ and $2x10^{-4}$ 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.

$1x10^{-4}$

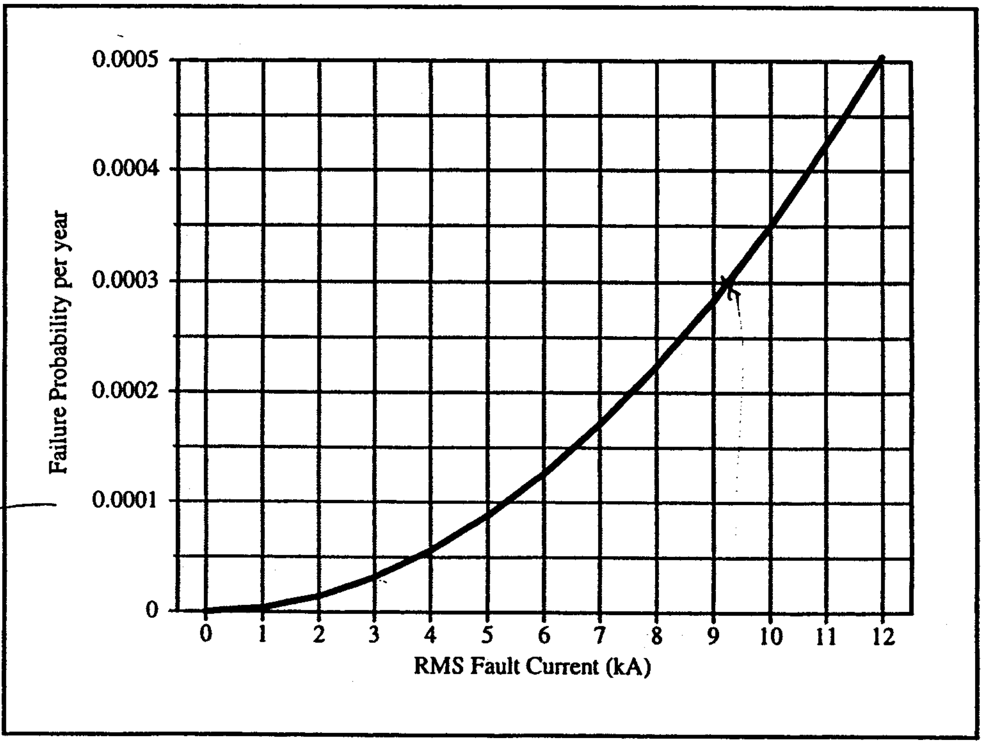

Figure 6 Eventful Tank Failure Probability Vs RMS Fault Current

meter Vertical

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 8×10^{-5} to 2×10^{-4}. If 10 kA is available the probability of eventful failure becomes 3.4×10^{-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.

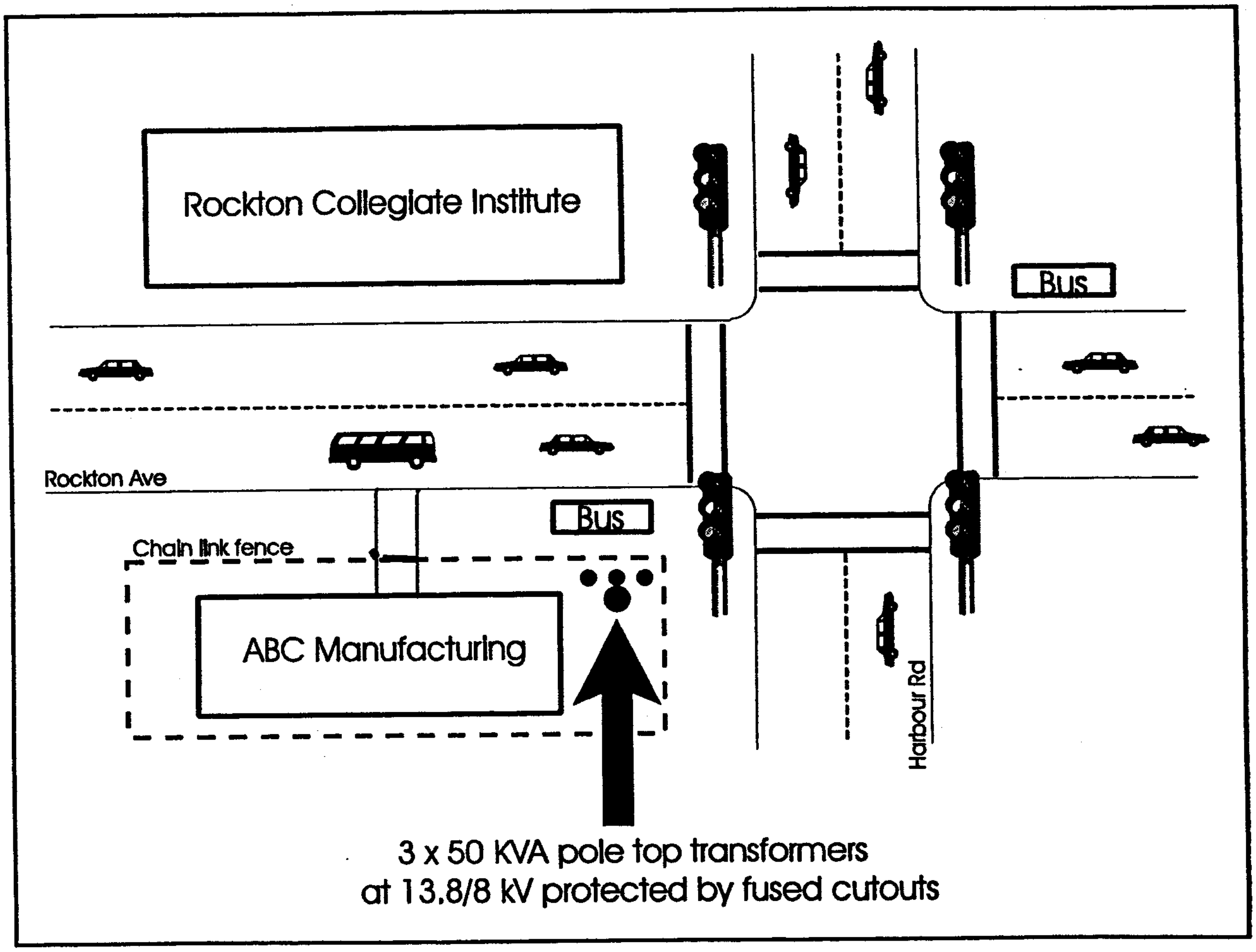

Figure 7 Example - ABC Manufacturing Site Overview

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 $\{(8 \times 5)+(4 \times 2)\} \times 52 = 2496$ 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
$\lambda_T = 0.03$

$P = 8 \times 10^{-5} \times (5)^2 \times (1.5)^2 \times 0.03 = 1.34 \times 10^{-4}$

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

$P_{total} = P \times 3 = 4 \times 10^{-4}$

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 = $4 \times 10^{-4} \times 1 \times \$12{,}000 = \$4.80$ per year

Case 2 Harm to Utility Employee
Risk = $4 \times 10^{-4} \times 1.4 \times 10^{-5} \times \$1{,}000{,}000 = \$0.57$ per year

Case 3 Harm to a Public Person
Risk = $4 \times 10^{-4} \times 0.285 \times \$100{,}000 = \$11.46$ 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.

REFERENCES

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.

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MINIMIZING POLE TOP TRANSFORMER TANK FAILURES

AUGUST 1997

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Distribution
Appendix 2
Attachment E

Automatic Sleeve Replacement

Newfoundland Power Inc.

Prepared by
Keith Whiteway, P. Eng.

June 2003

Table of Contents

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

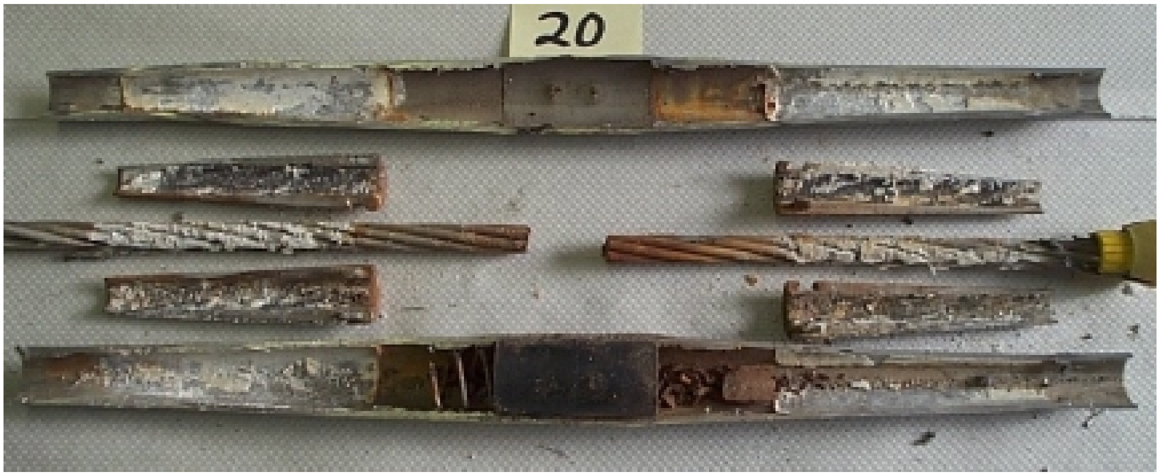
APPENDIX B

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.

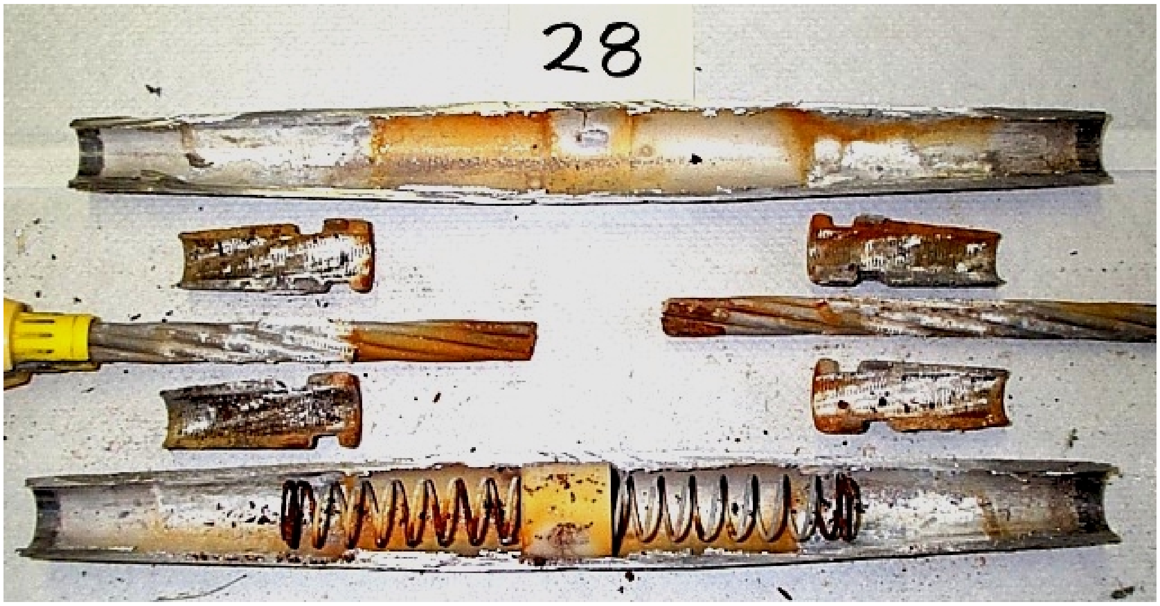
Automatic Sleeve - Glovertown

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.

Distribution
Appendix 2
Attachment F

Porcelain Cutout Replacement

Newfoundland Power Inc.

Prepared by
Keith Whiteway, P. Eng.

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.

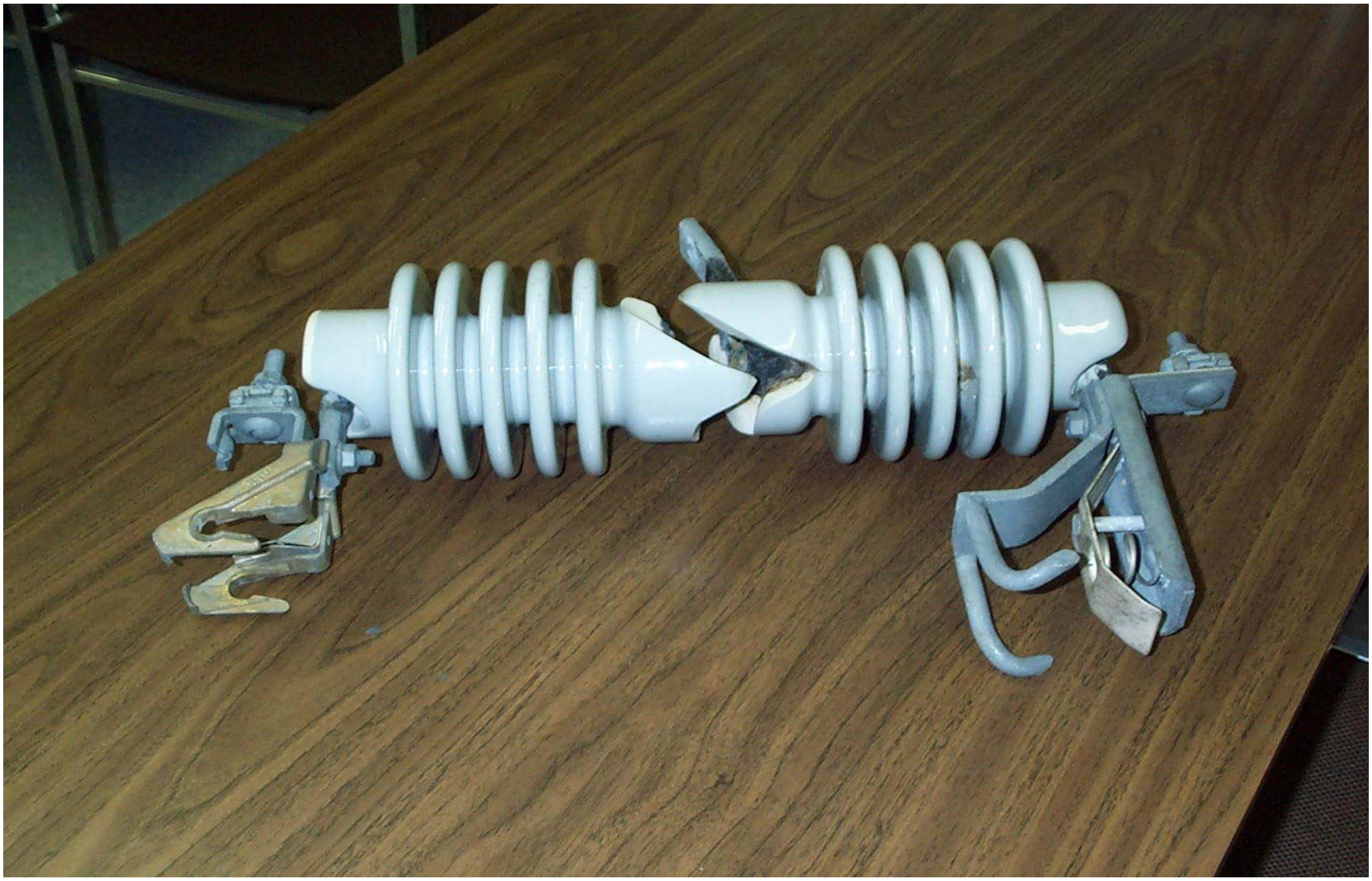
In addition to the above, as part of the annual inspection process, it is anticipated that approximately 1,000 defective cutouts will be identified per year. The annual cost of the material and labour to replace these additional units would be approximately $140,000.

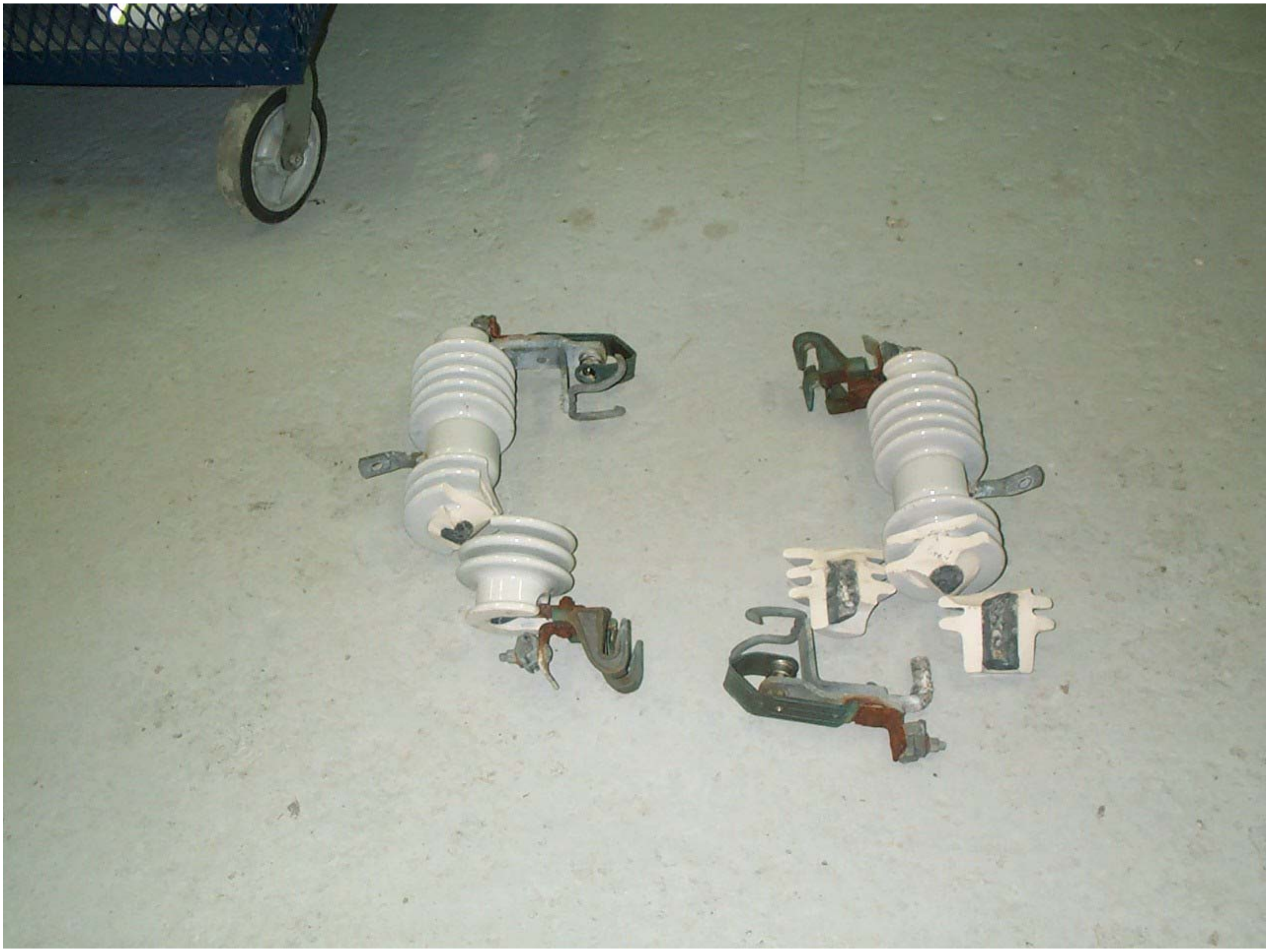
Recommendations

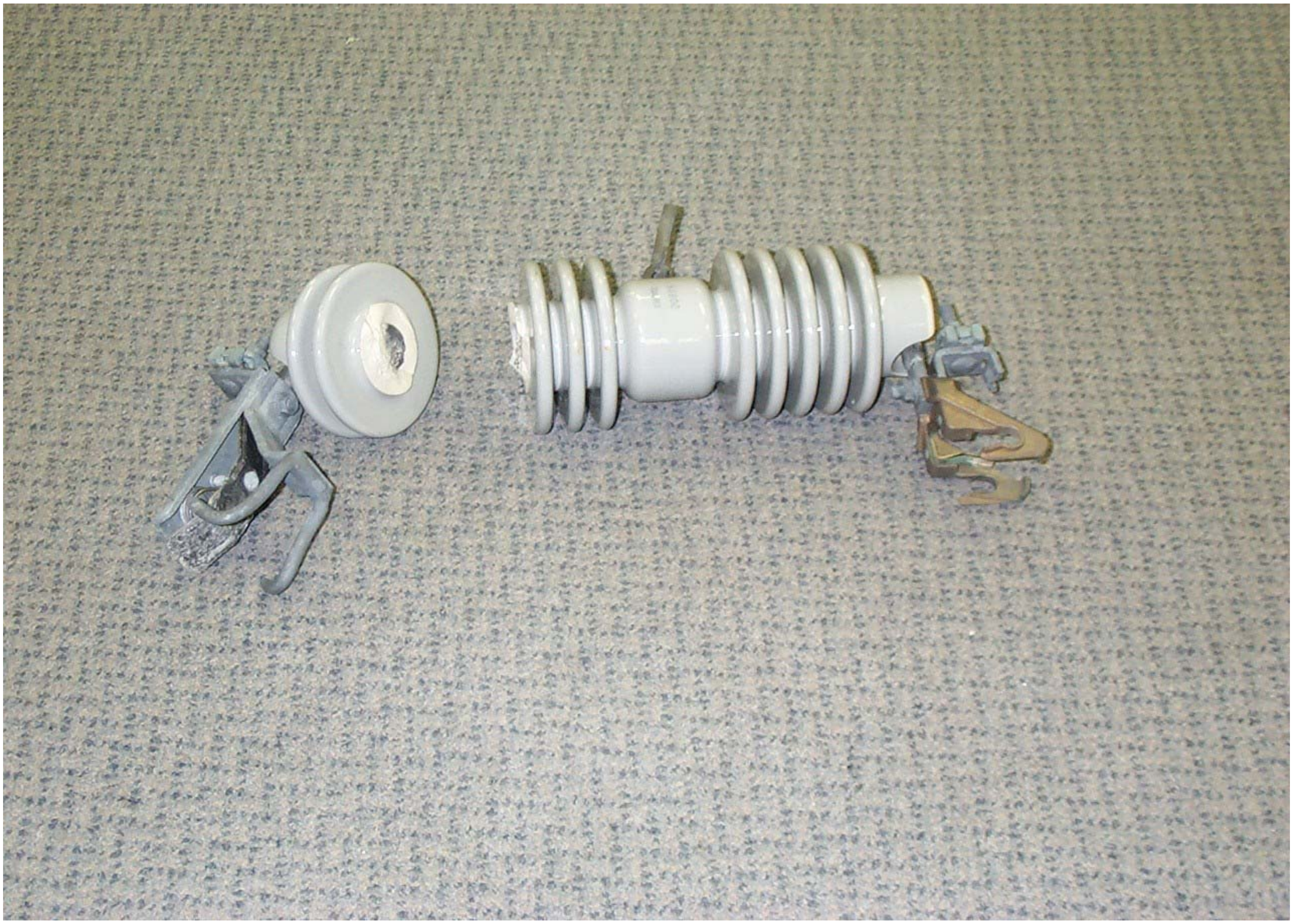
The following action is recommended with respect to porcelain cutouts.

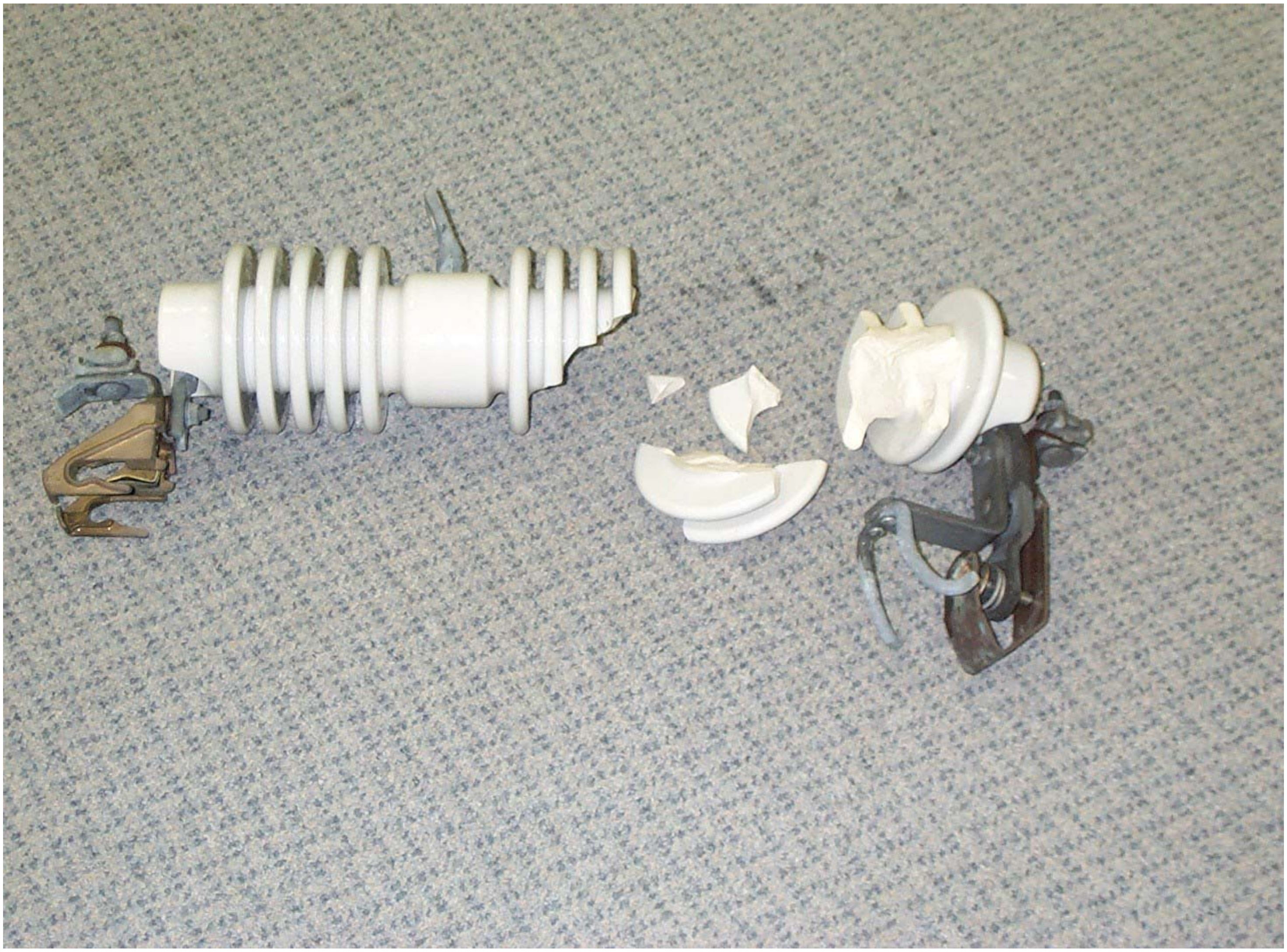
- Adopt polymer insulated cutouts as the new cutout standard.
- Discontinue the use of porcelain cutouts.
- As part of the annual distribution line inspection program identify defective cutouts i.e. ones that have visible evidence of cracks.
- In the year following the annual inspection remove the defective cutout from service.
- Monitor future porcelain cutout failures to determine whether additional measures such as an accelerated replacement program is necessary.

APPENDIX A









Distribution
Appendix 2
Attachment G

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.

Figure 1
Number of Underground Service Faults by Area

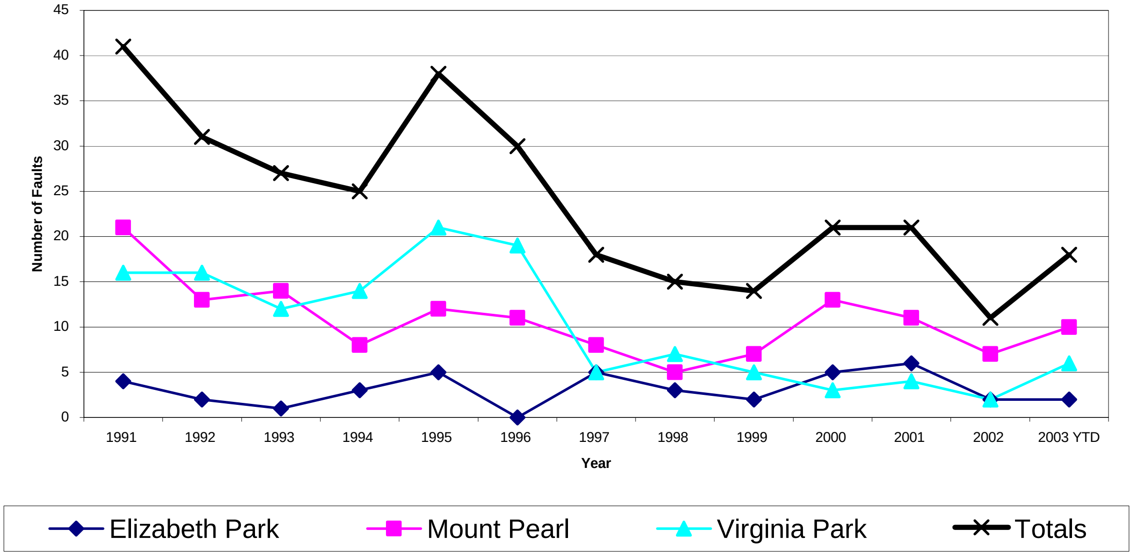
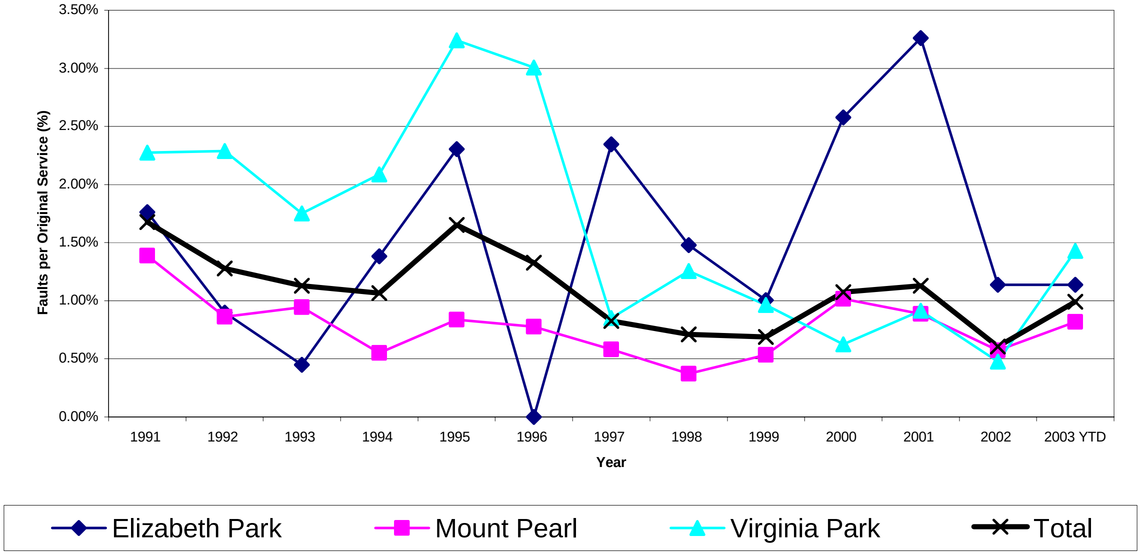


Figure 2
Faults as a Percentage of Original (Unreplaced) Services



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).

Distribution
Appendix 3
Attachment A

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.

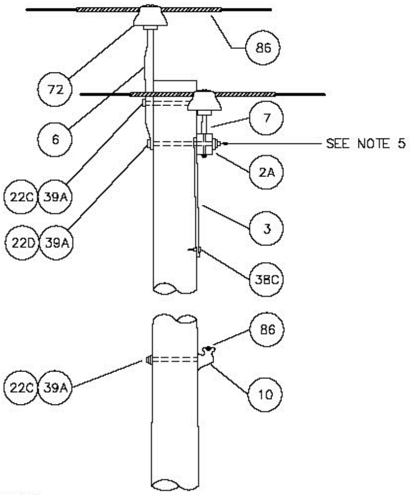
Overall, the $1,099,000 investment to improve areas of the feeder with known problems will result in an improved reliability for the customers. Due to the size of the project and nature of the work, it is proposed to complete all the work over a two-year period.

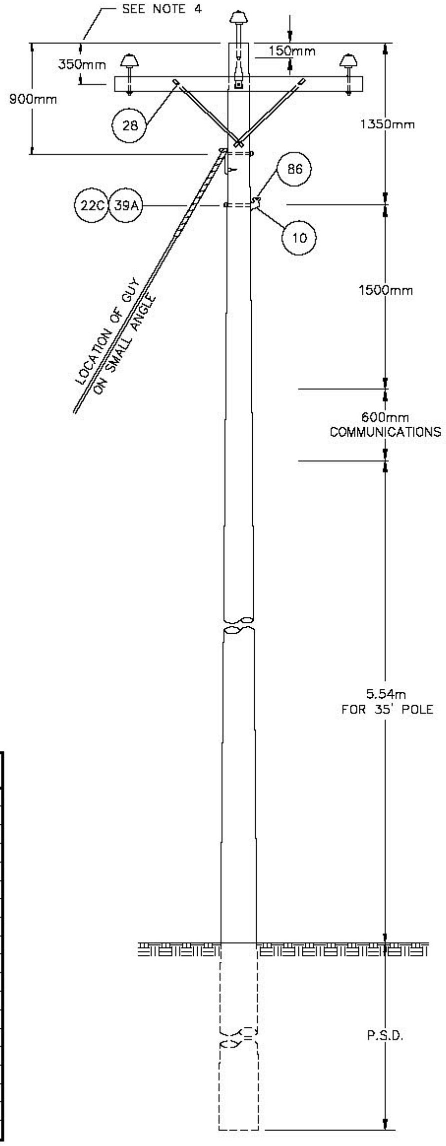
- 2004 – complete work in sections 7.2, 7.4.1 and address deficiencies as per the 2003 Distribution Feeder Inspection. $699,000

- 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)

G. Richard Spurrell

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

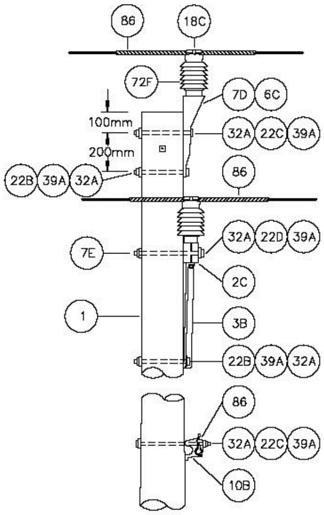
Date: 98-10-30

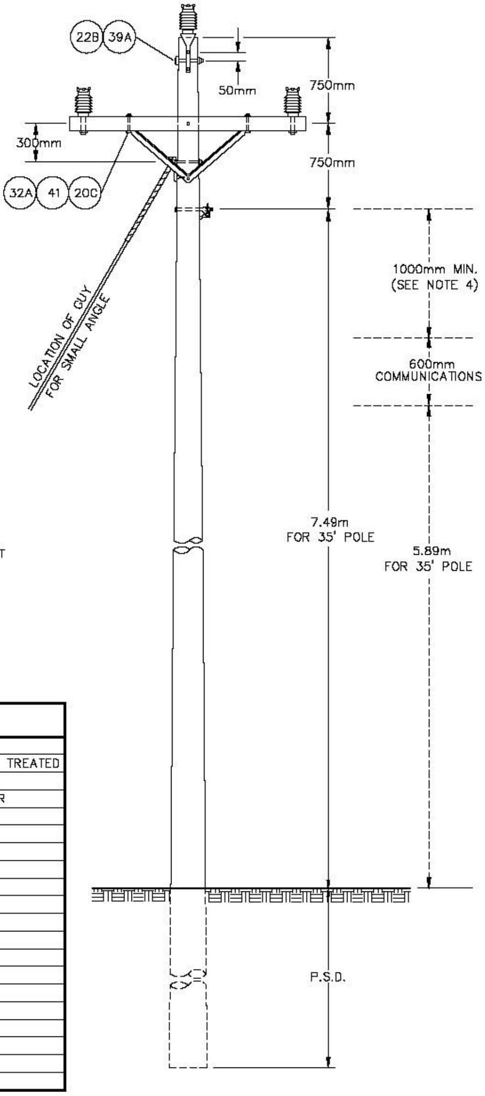
Drawn: K.L.S.

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)

R. KEITH WHITEWAY

SIGNATURE

DATE

DISTRIBUTION STANDARDS

NEWFOUNDLAND POWER
A FORTIS COMPANY

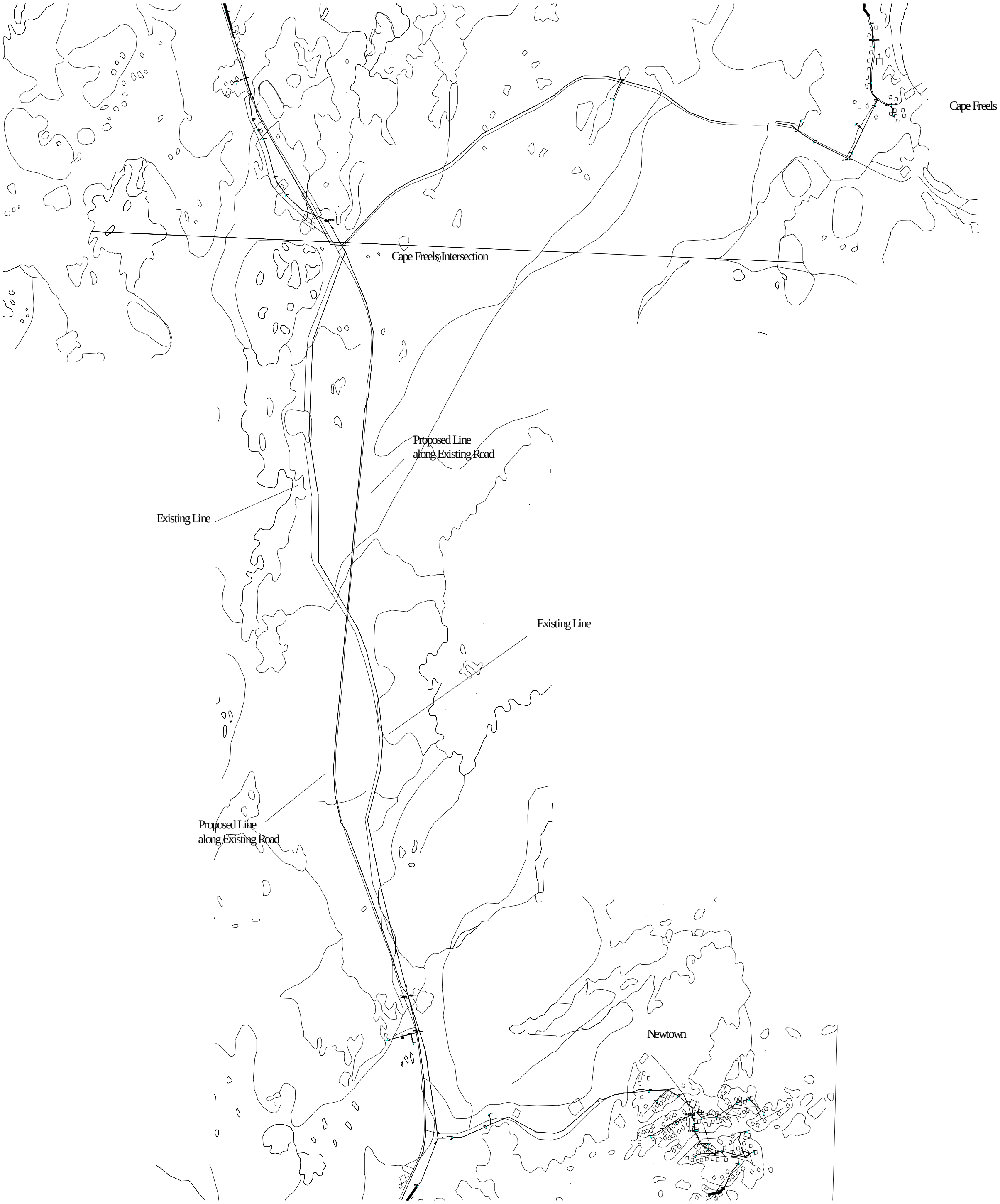
PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN F0032
which is valid for the year 1999

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

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

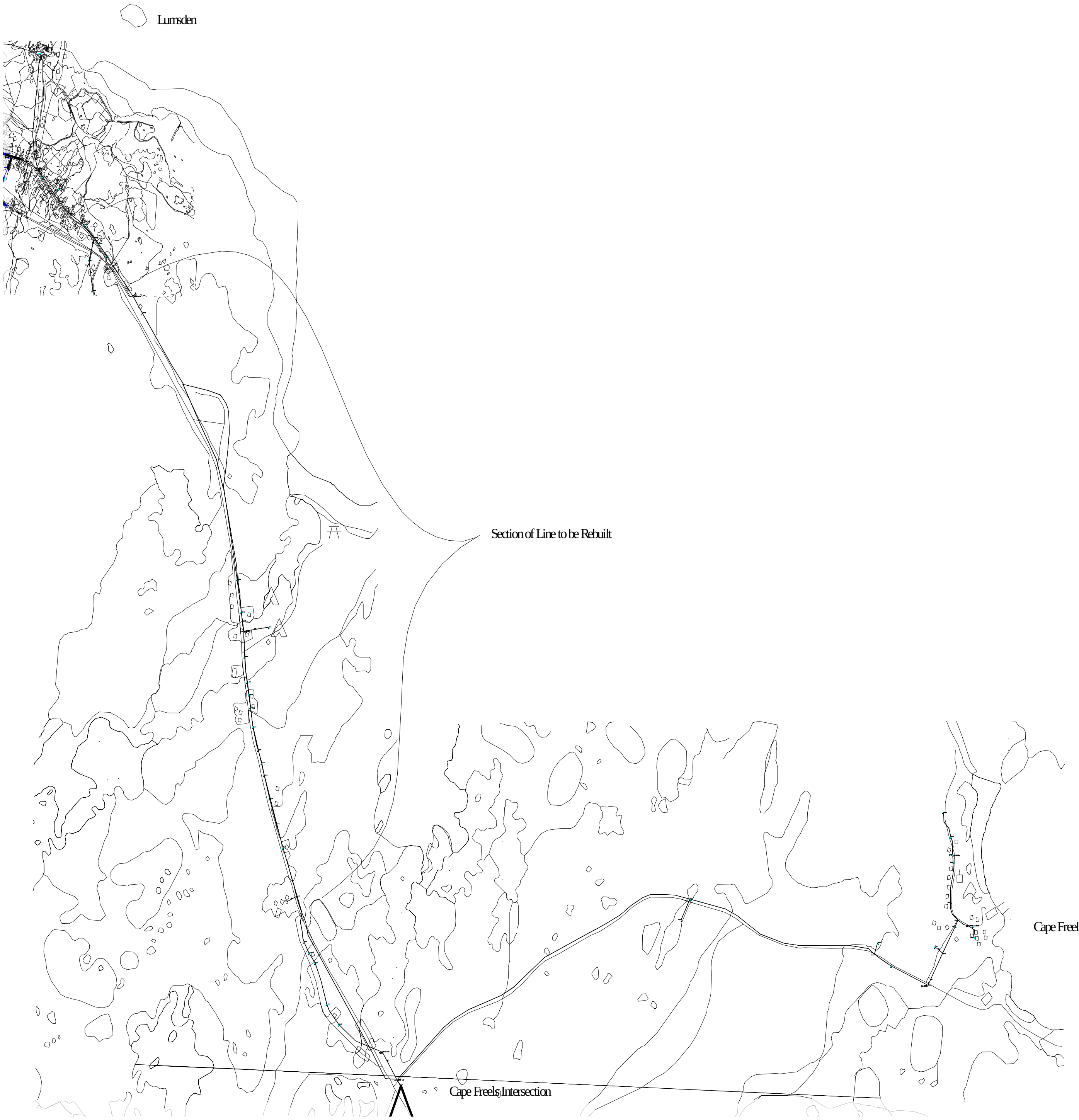
Appendix C

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

Distribution
Appendix 3
Attachment B

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 (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	

Distribution
Appendix 3
Attachment C

Pulpit Rock Substation
Loading and Reliability

June, 2003

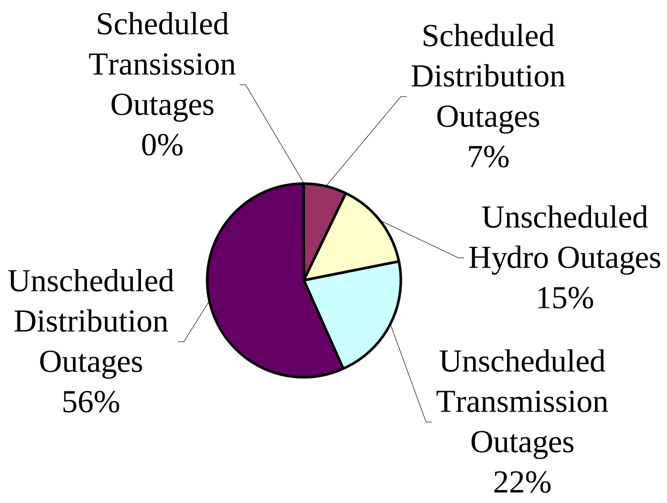
Table of Contents

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.

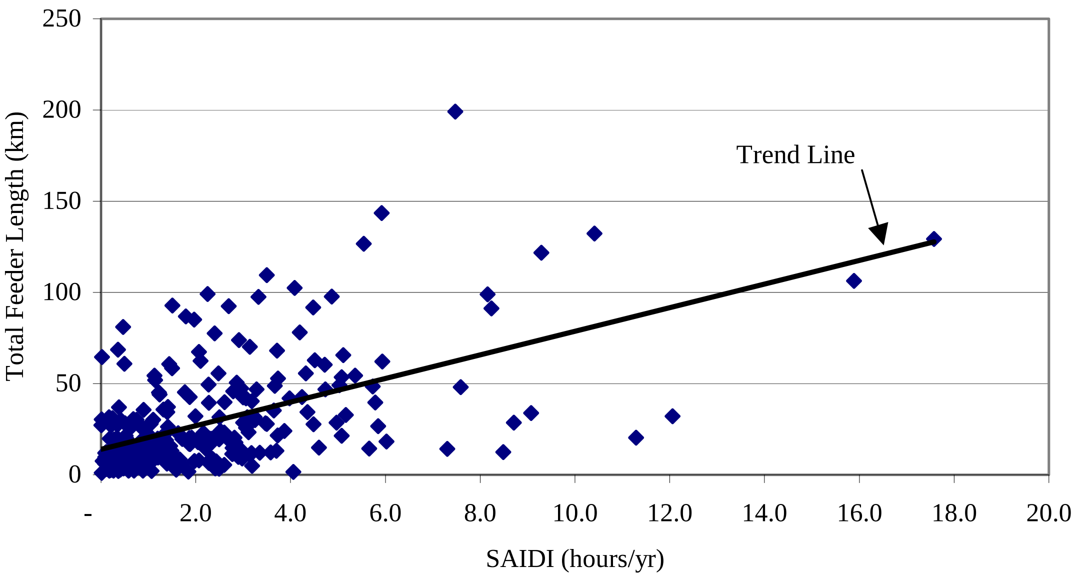
The combined peak load of PUL-01 and PUL-02 is forecast to be 860 Amps in 2003. This exceeds the emergency rating of either the PUL-01 recloser (850 Amps) or the PUL-02 recloser (800 Amps). As a result, the backup for recloser failure requires offloading customers from PUL-01 onto the Virginia Waters 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

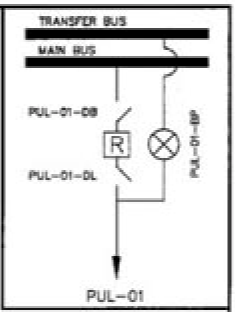
Existing PUL-01

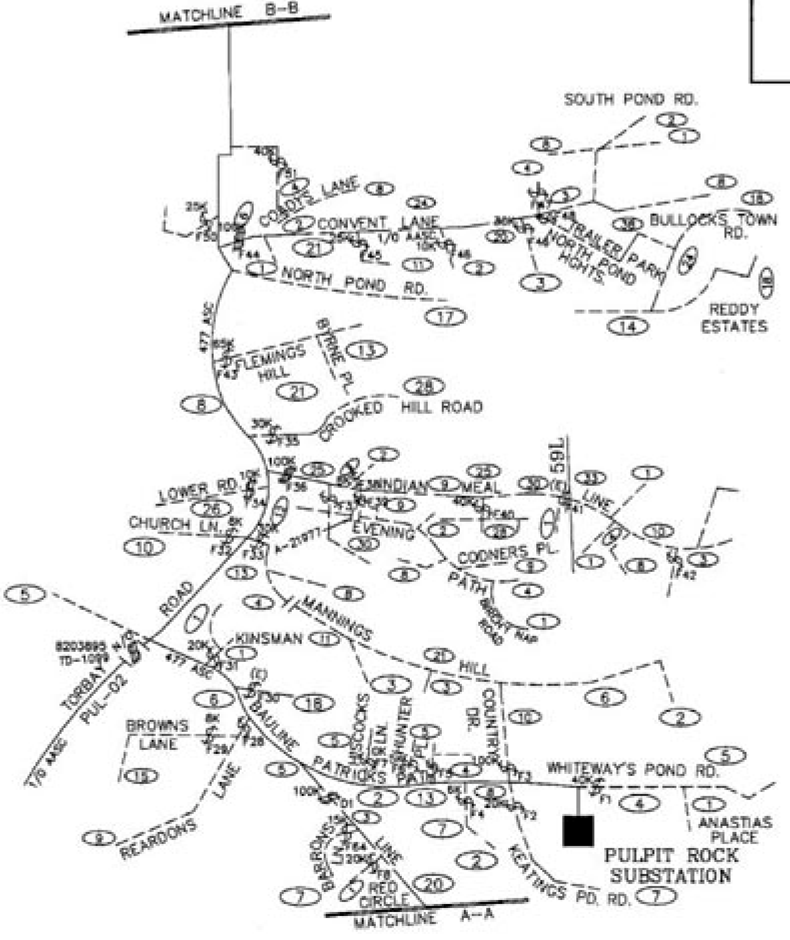
NOTE:

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



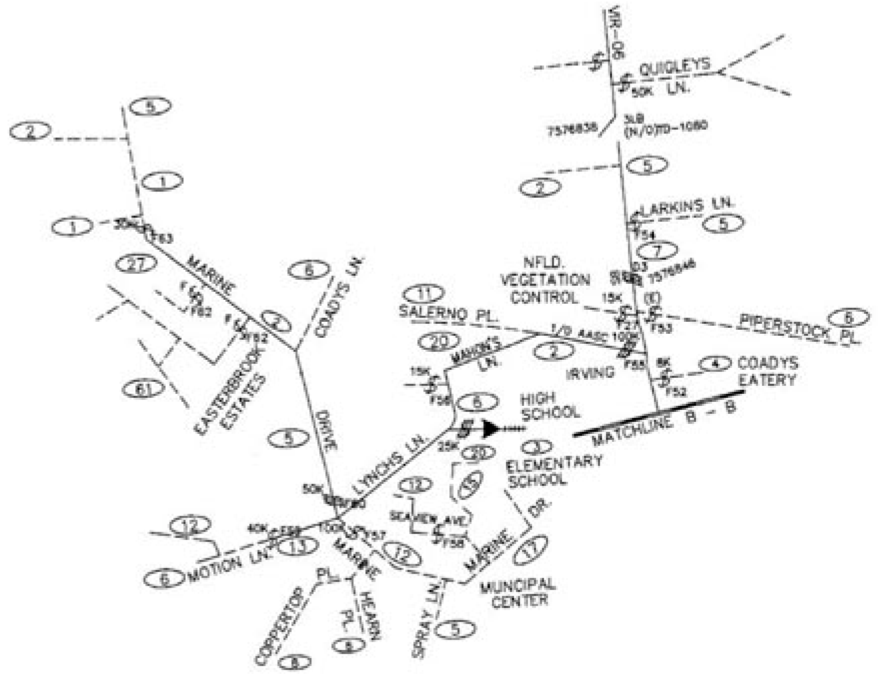


2031

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 1 OF 3

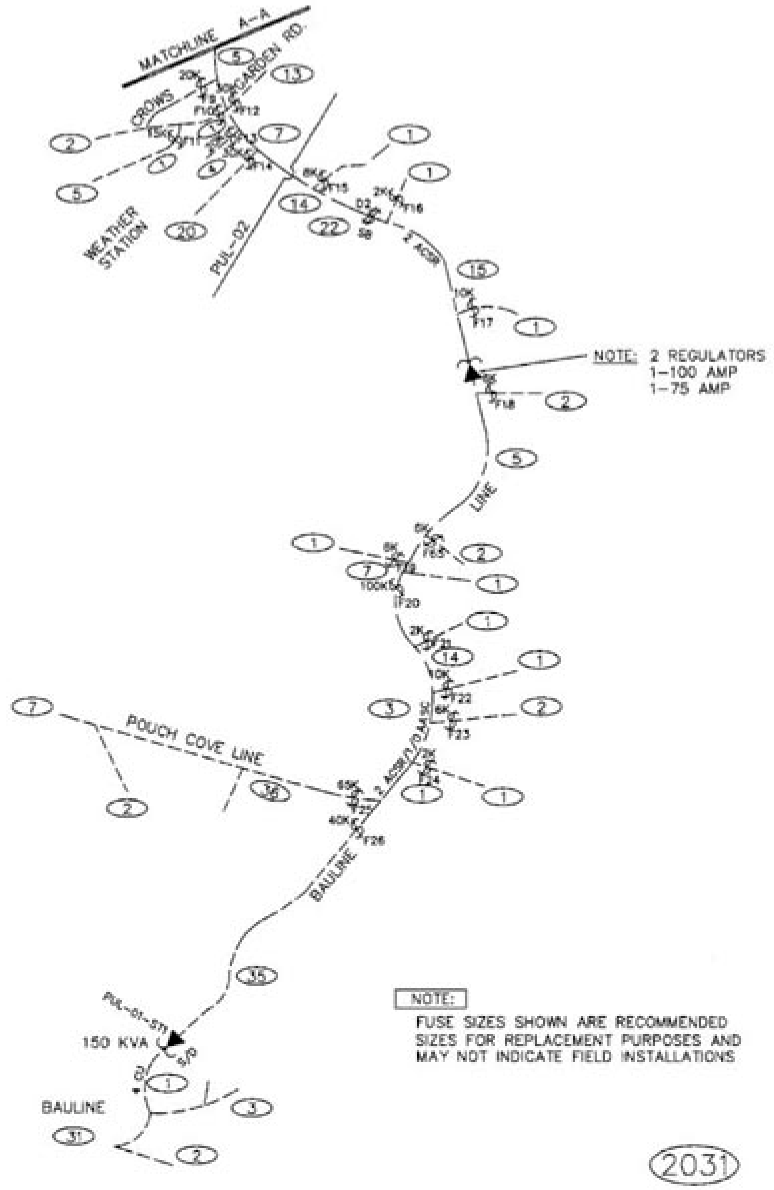


2031

NEWFOUNDLAND
POWER
A FORTIS COMPANY

DWG. REVISION DATE: 99-03-09
C/C REVISION DATE: 01-05-30
APPROVED BY: ________ ________

VOLTAGE: 12.5kV
FEEDER NO.: PUL-01
SHEET 2 OF 3



NOTE: 2 REGULATORS
1-100 AMP
1-75 AMP

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

2031

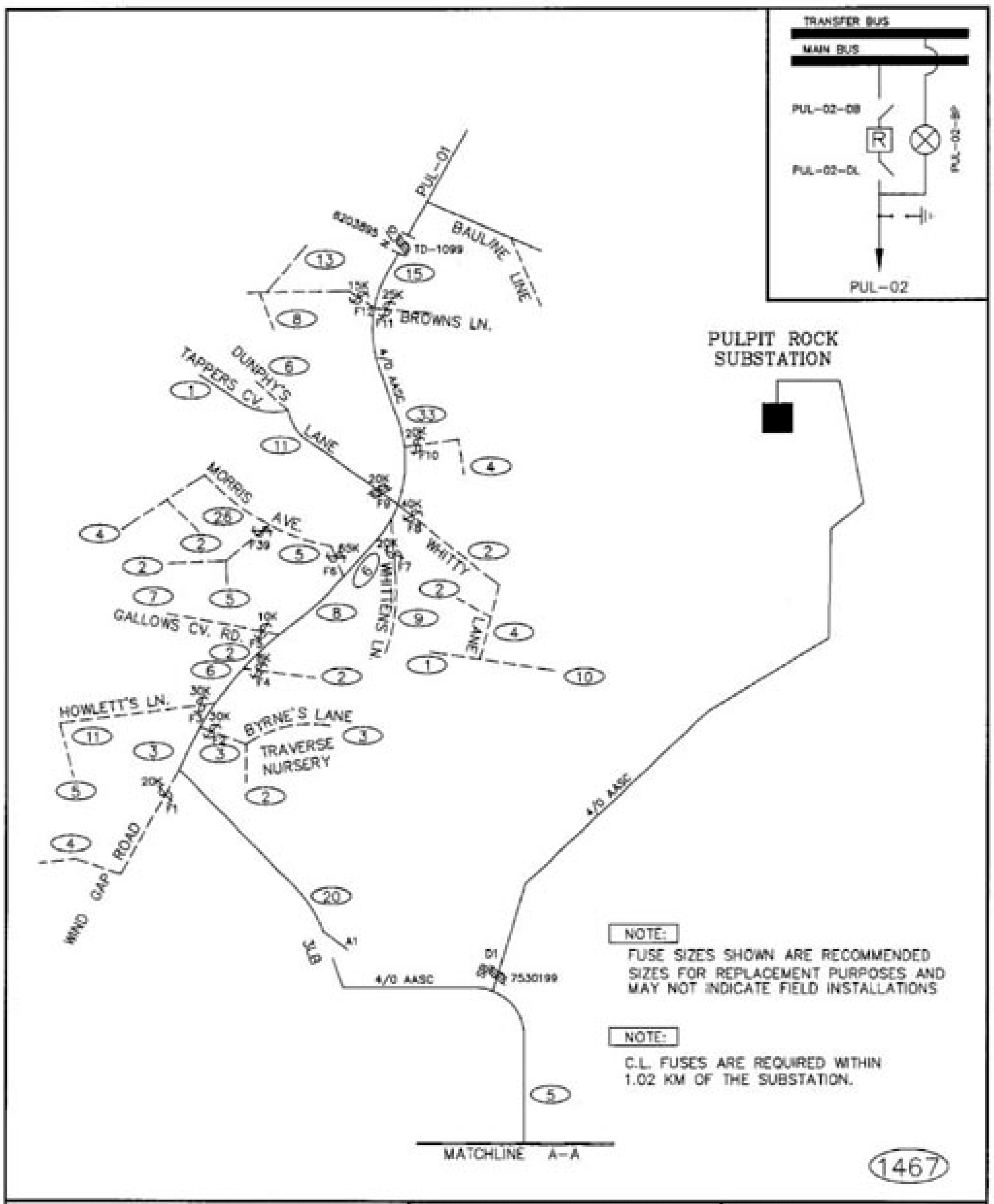
NEWFOUNDLAND POWER
A FORTIS COMPANY

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

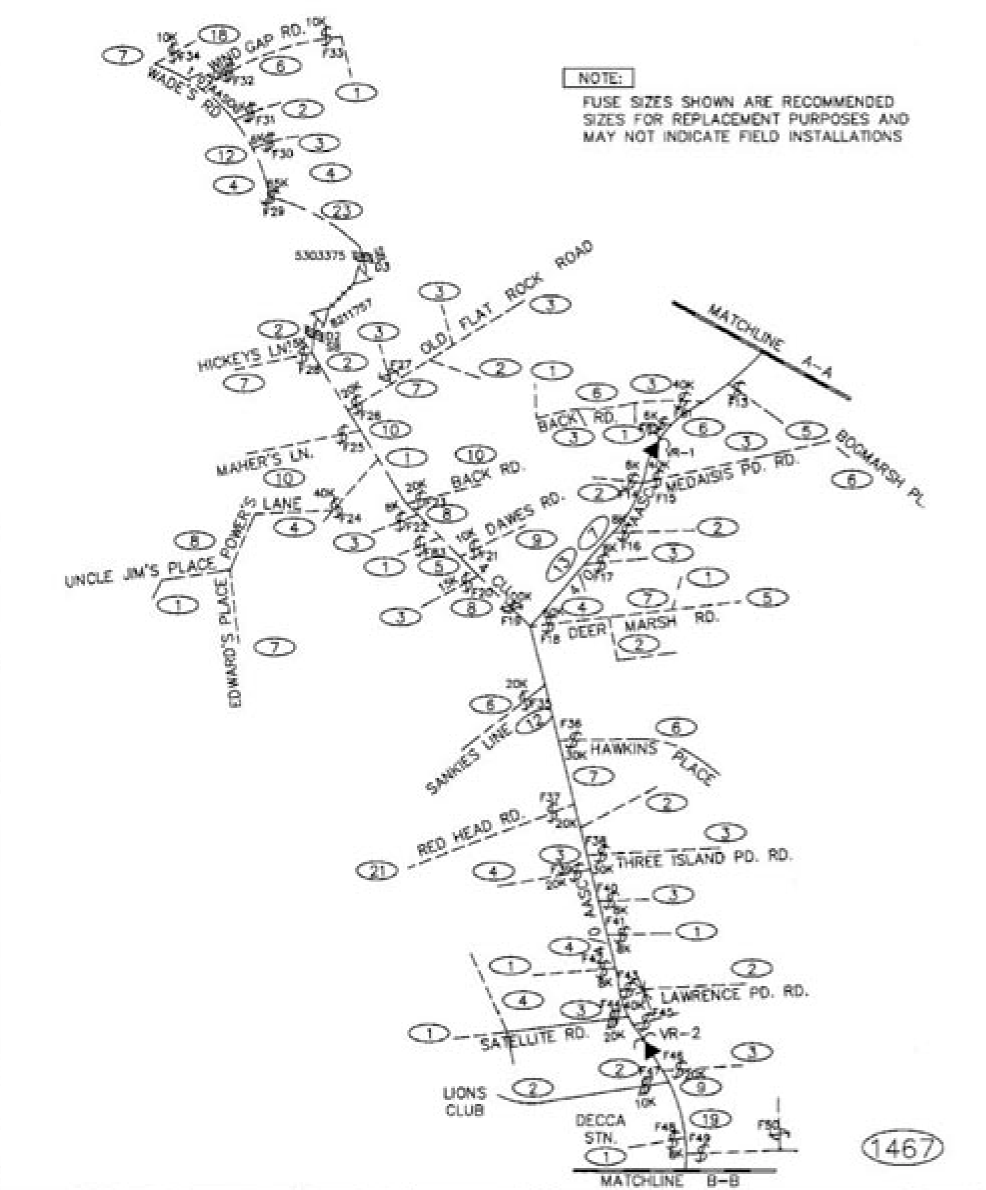


NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS

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-02
APPROVED BY:	SHEET 1 OF 3



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

NEWFOUNDLAND POWER
A FORTIS COMPANY

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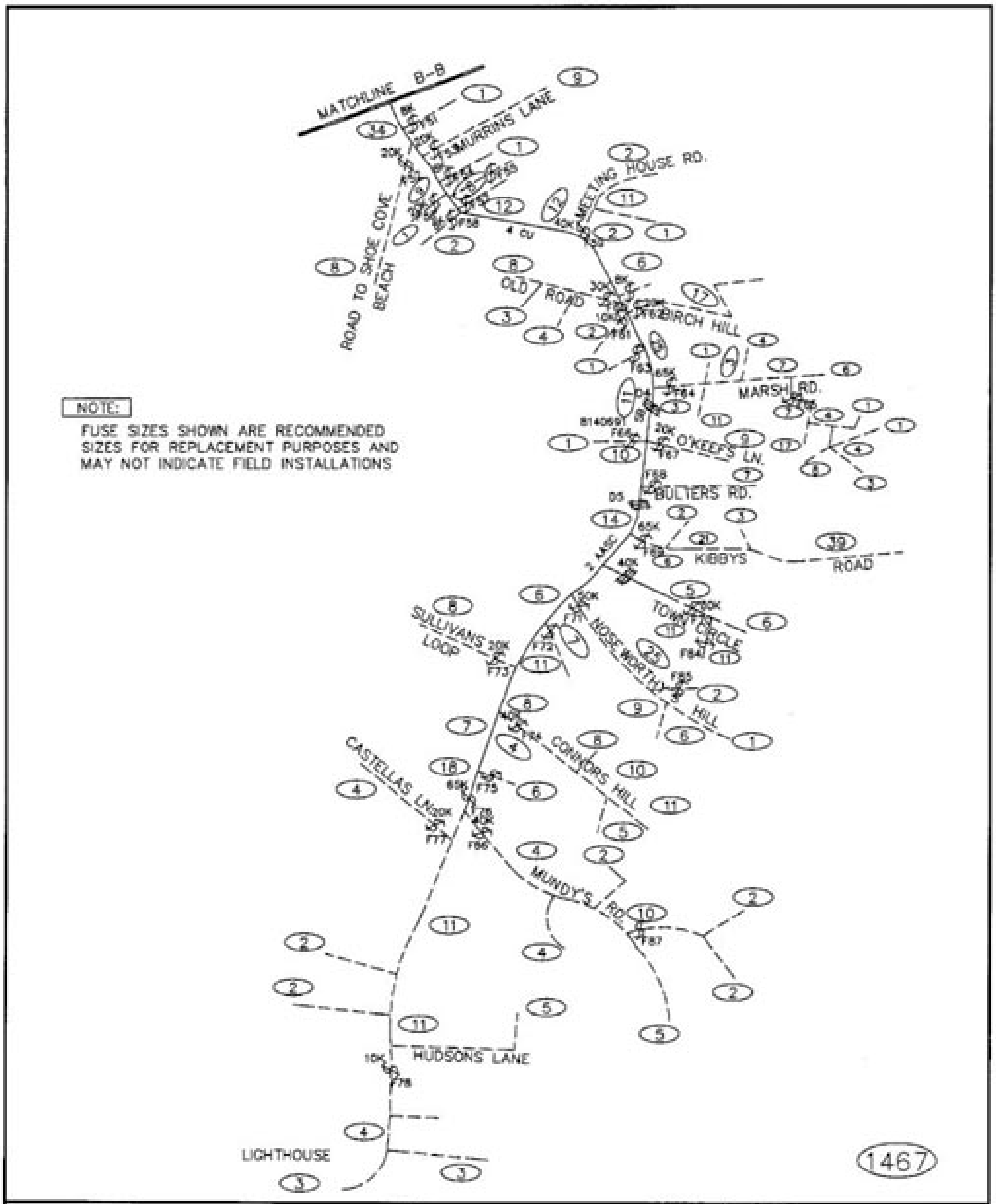
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-02 SHEET 2 OF 3
	APPROVED BY: ________ ________	



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:	

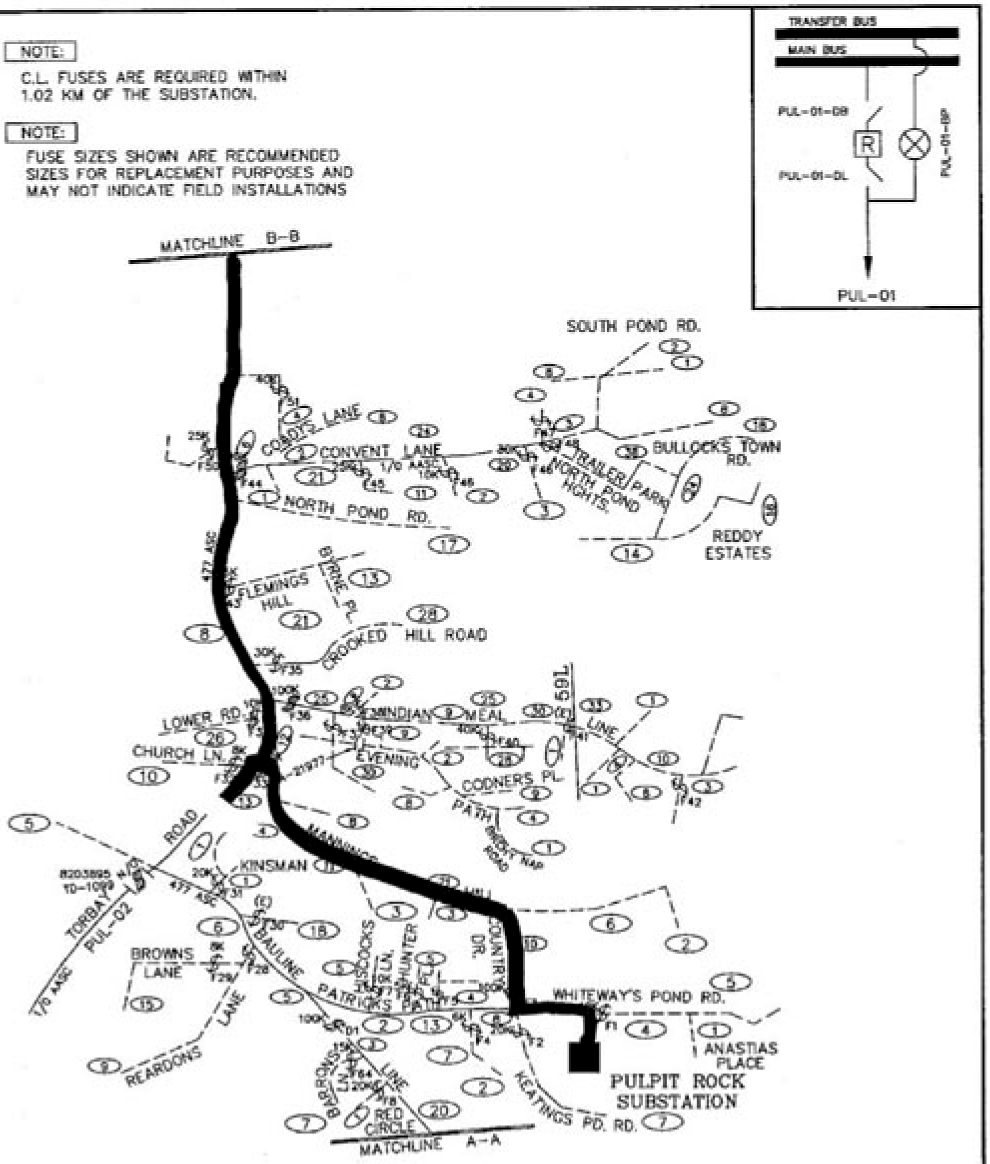
Proposed PUL-01

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



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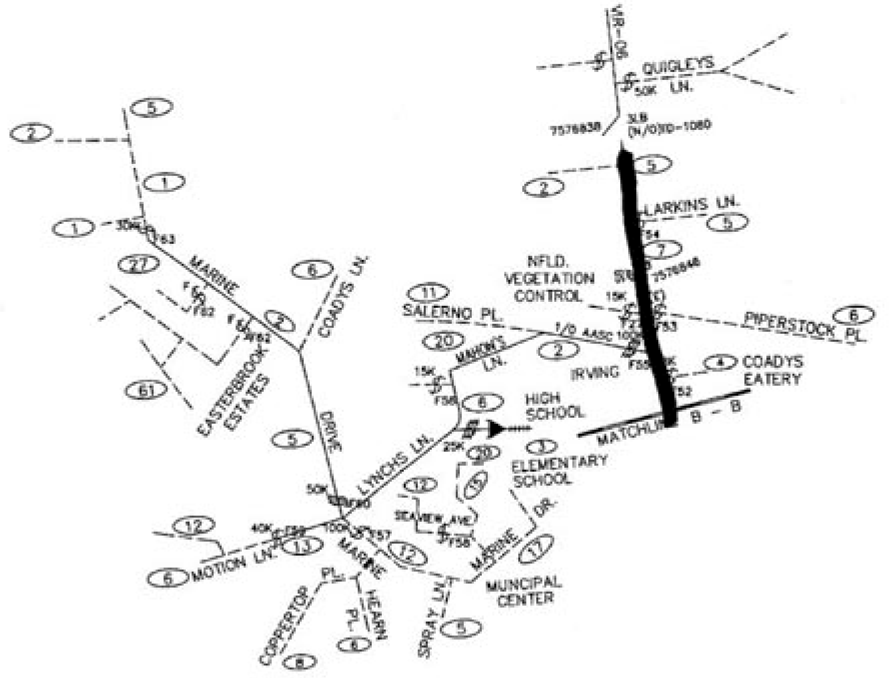
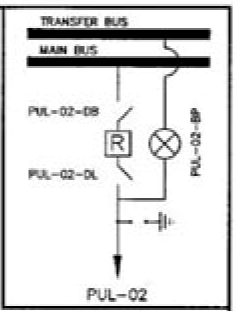


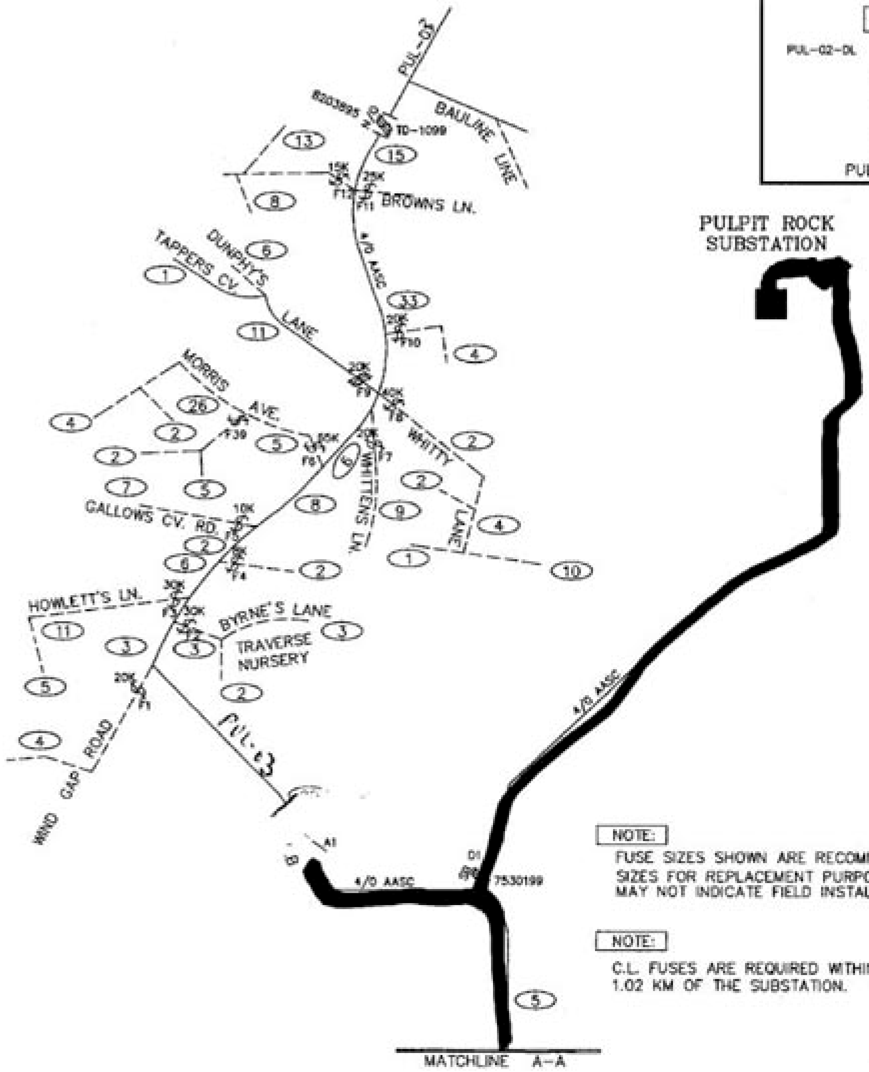
NEWFOUNDLAND POWER
A FORTIS COMPANY

DWG. REVISION DATE: 99-03-09
C/C REVISION DATE: 01-05-30
APPROVED BY: ________ ________

VOLTAGE: 12.5kV
FEEDER NO.: PUL-01
SHEET 2 OF

Proposed PUL-02





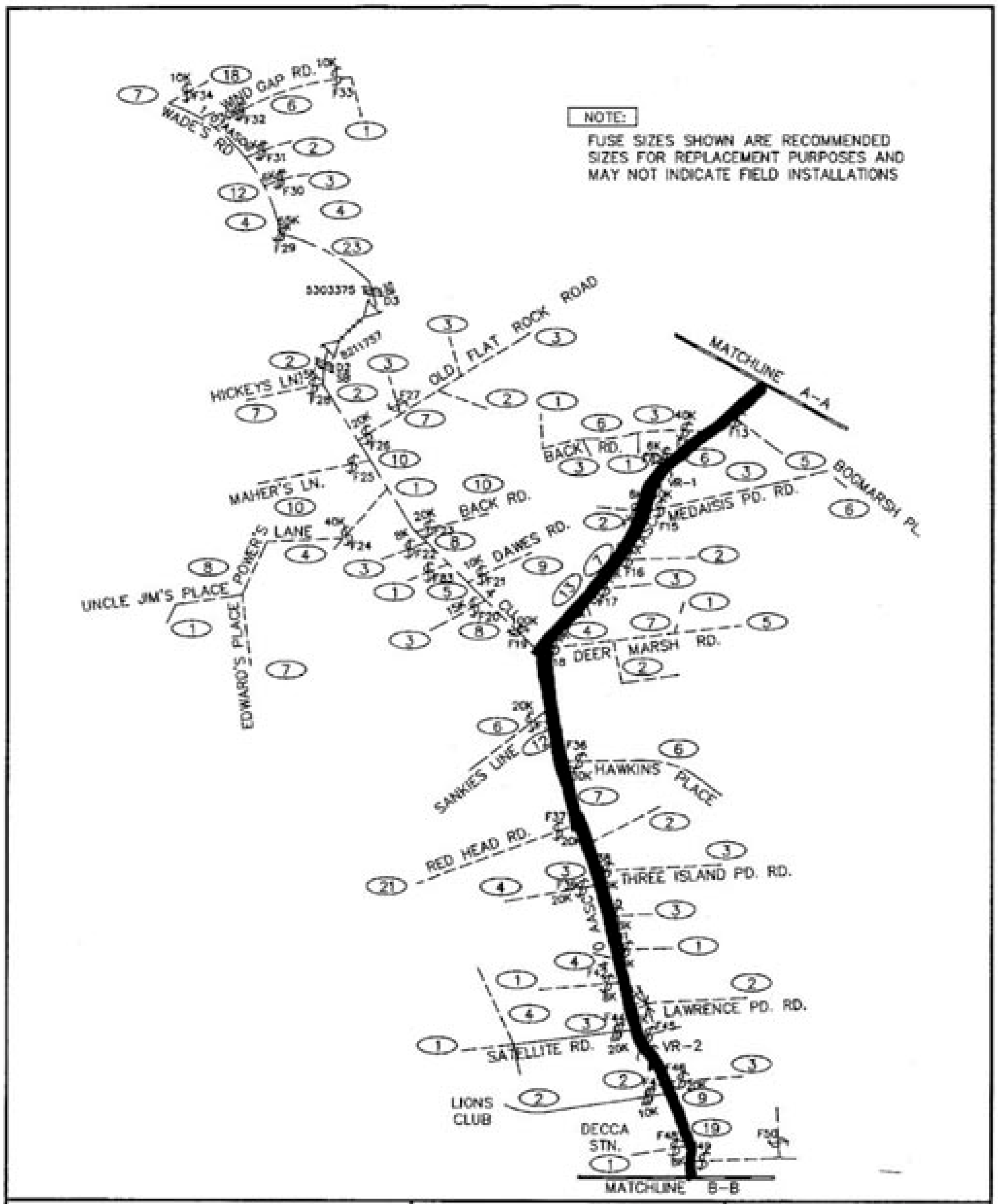
NOTE:

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-02 SHEET 1 OF 3
	APPROVED BY:	



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

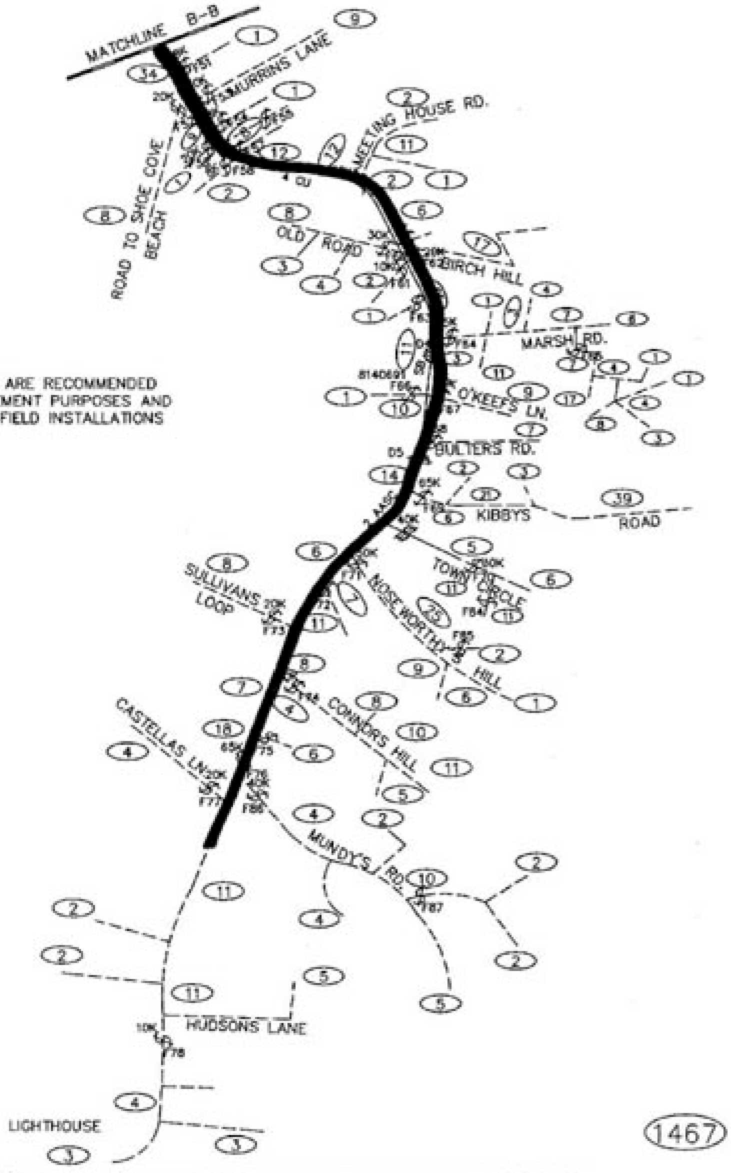
NEWFOUNDLAND POWER
A FORTIS COMPANY

DWG. REVISION DATE: 02-11-19
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
C/C REVISION DATE: 01-05-30
APPROVED BY:

VOLTAGE: 12.5kV
FEEDER NO.: PUL-02
SHEET 3 OF 3

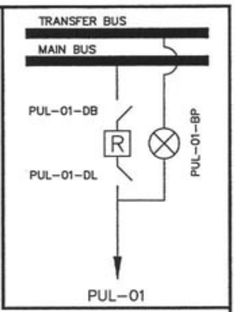
Proposed PUL-03

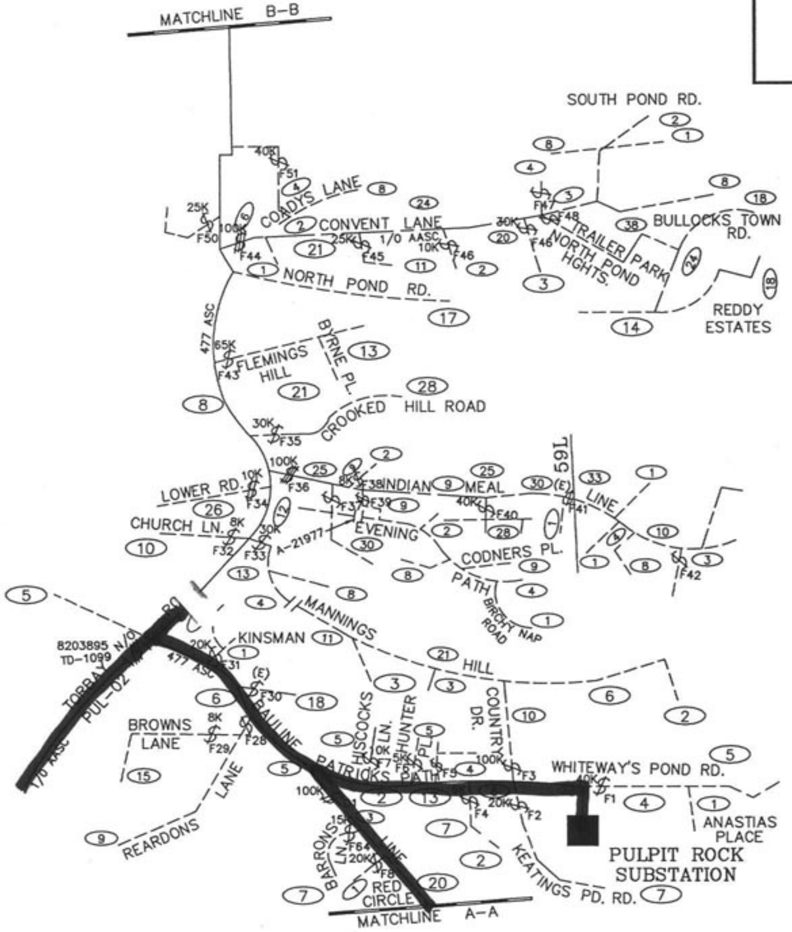
NOTE:

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

NOTE:

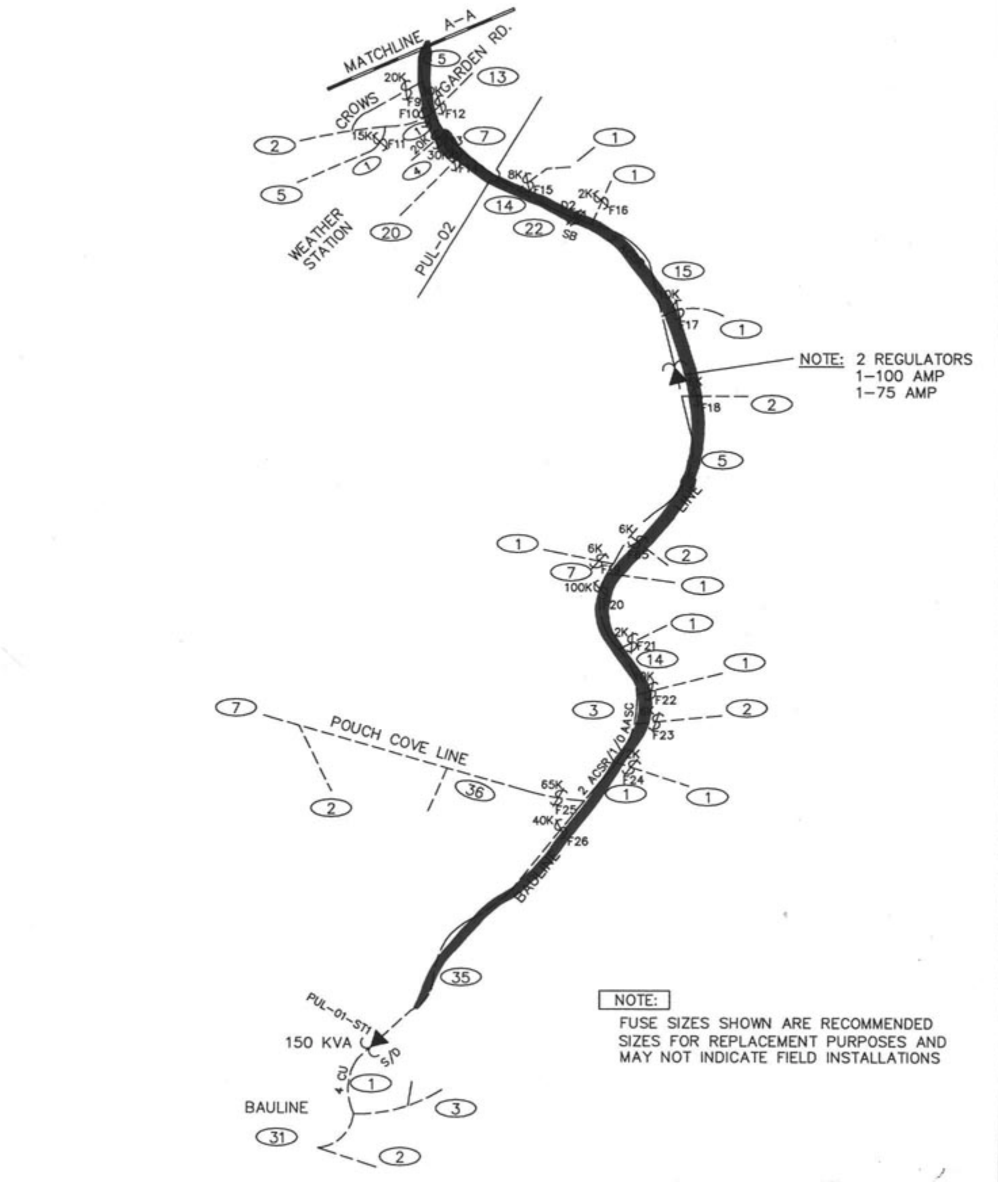
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS





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



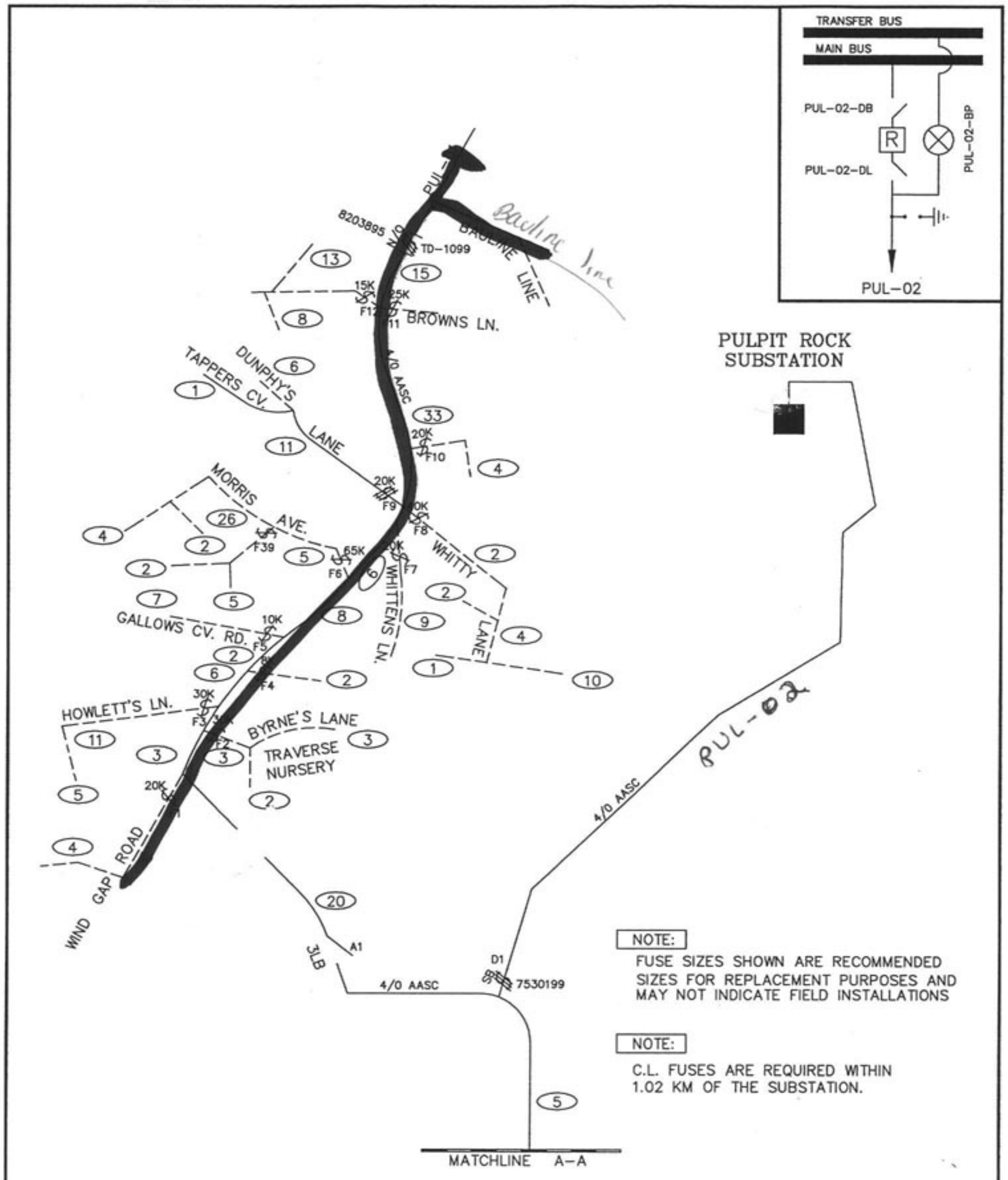
NOTE: 2 REGULATORS
1–100 AMP
1–75 AMP

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
C/C REVISION DATE: 01–05–30
APPROVED BY: ________ ________

VOLTAGE: 12.5kV
FEEDER NO.: PUL-03
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
C/C REVISION DATE: 01-05-30
APPROVED BY: ________ ________

VOLTAGE: 12.5kV
FEEDER NO.: PUL- 03
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.

Distribution
Appendix 4
Attachment A

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

		Operating	Transformer		2002							Max.
		Voltage	Capacity - MVA		Peak		Forecasted Undiversified Peak - MVA					XFMR.
Substation (Notes)	**Des.**	**(kV)**	**Rating**	**Existing**	**MVA**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**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 Voltage	Transformer Capacity - MVA		2002 Peak	Forecasted Undiversified Peak - MVA						Max. 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

Technical Criteria

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

Planning Methodology and the Development of Alternatives

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:

Alternative #1

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.

Alternative #3

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							
	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	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%

	CAPITAL EXPENDITURE IN YEAR BY ASSET							
	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	**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	Distribution	Capital Revenue Requirement	Present Worth Benefit	Cumulative Present Worth Benefit
	38.5 yrs 4% CCA	30.4 yrs 4% CCA			
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	

YEAR	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE		Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
	Substation	Distribution						
	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	**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	Distribution	Capital Revenue Requirement	Present Worth Benefit	Cumulative Present Worth Benefit
	38.5 yrs 4% CCA	30.4 yrs 4% CCA			
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%

	CAPITAL EXPENDITURE IN YEAR BY ASSET							
	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			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**	**Distribution**	**Capital Revenue Requirement**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**
	38.5 yrs 4% CCA	30.4 yrs 4% CCA			
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

				Year of Expenditures Required for each Forecast		
Alternative # 1	**Distribution**	**Substation**	**Total Cost**	**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**			

Appendix E

CBS Long Term Study

					Year of Expenditures Required for each Forecast		
Alternative # 2		**Distribution**	**Substation**	**Total Cost**	**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

				Year of Expenditures Required for each Forecast		
Alternative # 3	**Distribution**	**Substation**	**Total Cost**	**Low**	**Medium**	**High**
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**		

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Volume IV
Expenditure Details, Reports and Studies

Information Systems

Project Title: **Application Enhancements**

Location: **Various**

Classification: **Information Services**

Project Cost: **$1,355,000**

This project consists of a number of items as noted.

(a) Business Support Systems

Cost: $189,000

Description: The purpose of this item is to enhance the processes related to the Company's financial, materials management and human resources applications. For 2004, the proposed enhancements include:

1. **Process Improvements**: Process improvements available as part of the upgrade to Microsoft Great Plains (from version 6 to version 7) include:

   - Application security enhancements: Security will be enhanced to provide additional control over sensitive application information. Access can be restricted to pay rates or project information without having to provide separate modified screens. Efficiencies will also be obtained through simplified methods of configuring user security.

   - Increased capabilities for importing data from external sources: This will eliminate re-keying data into Great Plains.

   - Improved access to application information through queries and reporting improvements: Reporting improvements make it easier to track and compare data revisions, access detailed transactions by date ranges and compare general ledger to project accounting information.

   - New multi-bin capabilities for inventory tracking and control at the bin level: This will enable inventory tracking making it easier to locate inventory, move inventory between bins, and track quantites at the bin level.

2. **<u>Bar Coding</u>**: This item involves the implementation of bar coding technology for the central stores location. This includes the use of three portable devices to capture information when receiving, issuing, and transferring inventory, as well as during physical inventory counts. Benefits include:

   - Increased productivity of the storekeepers at Central Stores. Use of bar coding for stock numbers, projects and employee numbers will reduce data entry during the receiving and issuing of inventory, thereby improving the accuracy of inventory records, which will reduce the time to locate inventory and reduce stock outs.

   - Improved management of small tools items, such as gloves and safety glasses, will reduce the inventory for these items.

   - Enabling a storekeeper to perform other duties such as physical inventory counts during the regular working day, thereby avoiding overtime.

   - Less dependence on specific knowledge of individual storekeepers. Material is presently stored and picked based on the storekeepers' knowledge of where the material has been stored in the past. Bar coding will enable staff to quickly and easily locate inventory items in the warehouse without prior knowledge and with less experience.

   - Improved capturing and tracking of warranty information by equipment serial numbers. This would ensure that equipment with warranties closer to expiry are used first.

(b) Intranet/ Internet Enhancements

Cost: $147,000

Description: The purpose of this item is to enhance the Company's internal web site (Intranet) used by employees as well as the Company's Internet site used by the Company's customers and other interested parties. For 2004, the proposed enhancements include:

1. **<u>Changes to the Intranet:</u>** This item involves improvements to document management capabilities, information search and retrieval processes, as well as overall usability improvements. These enhancements will reduce the amount of time spent maintaining the Intranet site as well as allow Company staff to more effectively share documents. Benefits include:

- Reduced dependence on custom code for the Intranet. Internal programming staff will no longer need to perform as many software changes to add functionality or fix problems.

- Decentralized system administration functions. Allows the various Company departments and regions to organize, publish and share documents without the need for technical resources from IS.

- Improved search capabilities will allow employees to find information more quickly.

- An automatic notification mechanism will be implemented to inform necessary personnel when documents have been changed, reducing the time spent reconciling multiple versions of shared documents.

- Enhanced security by incorporating the employees' Company network account and password.

2. **Changes to the Company's Internet site:** This item involves improvements to the customer notification and follow-up process related to customer-initiated emails. Enhancements to the login procedures will make it easier for customers to utilize the on-line services provided in a secure environment, as well as overall usability improvements. Benefits include:

    - Automatic notification of customer-initiated e-mails, whereby customers will receive immediate response from the Company with the expected follow-up timeframe based on the type of request made. This will improve the customer's experience with using the Company's website.

    - Improved customer login process will make it easier for customers to use the secure area on the Company's Internet site, as they can set their password to be something that is more easily remembered. Currently customers must know both their bill account and meter number, and they are unable to access their account without this information. Changing to a customer-defined password enhances customer service and promotes greater usage of the website.

(c) Operations and Engineering Enhancements

Cost: $661,000

Description: The purpose of this item is to implement improvements in the Company's operations and engineering applications in the specific areas of project management, asset management, work order management and outage management. The following are the individual initiatives within this item:

1. **Project Management Improvements**: This involves the implementation of "Microsoft Project Server" and "Project Professional" to enhance the Company's project management practices. Benefits include:

    - Improved consistency in how projects are planned, estimated and tracked by providing company-wide system parameters, project templates and project management guidelines.

    - A centralized database of projects and resources will reduce the manual effort in e-mailing and copying projects by regional personnel into the central projects file located at Head Office.

    - Improved project-reporting capabilities for project leaders responsible for tracking individual projects as well as for managers who track the overall progress of projects.

2. **Crew Scheduling Efficiencies**: This involves enhancements to existing applications in the outage management and asset management areas. This will involve process improvements in the management of field crews during routine asset maintenance and outage situations. To facilitate improvements in the scheduling of crews for routine maintenance, the Company will upgrade the existing Avantis.PRO asset management software. To facilitate improvements in crew efficiency during outage situations, enhancements to the existing outage management data and in-house developed application are proposed.

    Engineering, technical, and skilled trades staff perform work involving maintenance, construction, customer requests and trouble calls. Work planning, scheduling, and tracking methods have been improved recently, especially in the area of maintenance. However, there are still opportunities in the coordination of demands and commitments across a variety of work sources through improved scheduling processes. In coordination with the Project Management Improvements initiative, this item will leverage the capabilities of the existing asset management software to provide more complete management information for workforce planning. Benefits include:

- Operational efficiencies through reduced overtime in outage situations by being able to identify potential trouble spots and dispatching crews geographically closer to the source of the electrical trouble.

- Improved management of maintenance personnel during routine maintenance by being able to associate available personnel and appropriate skill sets with the maintenance work.

- Improved information allowing customers to be better informed during power outages and allow for the better estimation of restoration times.

- Increased reliability by providing more accurate information and statistics to improve decision-making and identification of sections of the distribution system requiring maintenance or upgrading.

3. **Reporting Improvements**: This item involves the replacement of current information analysis and reporting processes with tools and processes better able to manage the financial aspects of projects being conducted by the Company. Benefits include:

   - Consolidation of reporting tools. The proposed reporting tools and processes are currently used to report other Company related information, thereby reducing the need for end-user training.

   - Provision of multiple reporting requirements within the same environment. Reports within Great Plains can be customized to meet specific user requirements, however there is an application restriction that allows only one version of a specific report to be used at a given time. There are several reports that have multiple purposes for multiple groups within the Company. This enhancement would allow the Company to satisfy multiple information requirements within the same reporting environment and reduce the need to modify the core Great Plains reports.

4. **Work Order Tracking**: This item involves improvements to the processes involved with ensuring that customer initiated work is effectively captured, scheduled and tracked. Benefits include:

   - Higher throughput of engineering work within the technical group.

   - Improved scheduling of customer driven work and management of customer’s expectations as well as enhanced customer status reporting capabilities.

   - Improved prioritization of workload through the use of software driven priority and project status functionality (currently a manual process), allowing the Company to focus on the highest priority work first.

- Improved process for establishing and meeting project schedules, including requirements for 3rd party work.

5. **SCADA Enhancements**: This item involves enhancements to the SCADA system intended to facilitate improvements to the Company's ability to efficiently and effectively manage the electrical system. Enhancements include:

   - Improvements to the user interface, including consolidating displays and implementing a tiered mechanism for managing SCADA alarms.

   - The development of new displays and the customization of monitoring and control functions.

   - The purchase of a SCADA module that will provide enhanced capability to electronically notify personnel (through cell phones, email, etc.) when there are power outages that have been detected by the SCADA system.

   - Increased integration with other applications such as Asset Management and Outage Management.

   - Expanded access to SCADA historical information.

   Benefits include:

   - Improved productivity of the System Control Center Operators.

   - Improved monitoring and control capabilities essential to ensuring the reliability of the electrical system.

   - Improved planning capabilities related to the Company's distribution system.

(d) Customer Service System Enhancements

Cost: $208,000

Description: The purpose of this item is to implement improvements in the customer service area. The following are the individual initiatives within this item:

1. **Equal Payment Plan**: Two enhancements will be made to the Equal Payment Plan (EPP).

   Weather Adjustment of the Equal Payment Amount: Currently, a customer's actual electrical consumption in the previous year is used to estimate consumption in the coming year. This estimated consumption is used to determine the equal monthly payment. As a result of this enhancement, during initial set up of the equal payment plan and during the annual review process, consumption will be reviewed to determine if the consumption reflects a "normal" year. If abnormal weather conditions existed (e.g. unusually cold or warm), actual consumption will be adjusted for weather. The future payment will then reflect consumption during a "normal" year.

   Equal Payment Review Improvements: Today, the equal payment plan of each of the over 30,000 EPP customers is reviewed four times per year to ensure the annual payments billed reflect actual consumption. This procedure is a mixture of automated and manual steps. If consumption trends indicate the monthly equal payment is substantially low or high, the customer is notified via a letter. The letter provides a new EPP amount, suggests the customer change the payment and explains the impact of not modifying the payment. This process is manually intensive and will be modified and further automated to make it more efficient and to provide more accurate results. Benefits include:

   - Improved service to customers by more accurately estimating their equal payment amount (based on "normal" consumption).

   - Reduced labour required to review a customer's EPP through further automation.

   - Efficiency gains in dealing with customers whose review indicates inadequate history or a significant change in payment. Presently analysts must manually check each situation in CSS, obtain the suggested payment provided there, and then go back to the manual system and add it in.

   - Improved access to customer information (payment, total consumption) regarding the proposed change to the EPP Monthly Payment.

2. **Meter Reading Improvements**: This initiative is focused on changes to the CSS to make the system capable of supporting AMR demand meters that will be purchased in

2004. Justification for purchase of these meters is provided in Volume III, Distribution, Appendix 1.

3. **Scheduling Improvements**: A new module for the current *Aspect* call centre software application that forecasts call centre staffing level requirements will be purchased and installed. This software tracks and analyses historical call volumes, models the required call centre resources to respond to anticipated call volumes for each half-hour increment of the day, and schedules the required shifts to cover the recommended level of customer service agents.

   Benefits include:

   - Optimization of customer service levels to ensure there are enough customer service agents in the call centre to meet customer demand.
   - Efficiency gains in the utilization of customer service agents. Forecasting to ensure the appropriate resources are available to meet customer service demand results in a more efficient allocation of the resources.
   - Additional capability to forecast agent staffing for outbound calling and e-mail responses.

(e) Various Minor Enhancements:

Cost: $150,000

Description: The purpose of this item is to complete enhancements to the Company's computer applications in response to unforeseen requirements such as legislative and compliance changes; vendor driven changes and employee driven enhancements designed to improve customer service or staff productivity. Examples of previous changes included a vendor driven upgrade to hand-held meter reading software, customer monthly consumption edit enhancements to improve customer service and government driven changes to income tax calculation in the payroll applications.

Project Title:	**Application Environment**
Location:	**Various**
Classification:	**Information Services**
Project Cost:	**$791,000**

This project consists of a number of items as noted.

Description: This project consists of upgrades to software components and processes related to the operation of the Company's business applications. For 2004, the proposed upgrades include:

1. **The Microsoft Enterprise Agreement**: This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

   Through the Microsoft Enterprise Agreement the Company achieves an overall cost savings. This is a fixed, annual price agreement based on the number of eligible desktops in the Company.

   In 2002 the Company investigated the various types of payment methods available for the purchase of the following Microsoft licenses: Microsoft Word, Microsoft Excel, Microsoft PowerPoint, Microsoft Access, Microsoft Outlook, and Microsoft SQL Server Client Access. The 3 options identified by the Company were:

   1. Do nothing now, and pay for net new licenses to upgrade in the future.
   2. Purchase a Microsoft Select Agreement (SA) for each instance of the software. This provides the Company with the ability to use the latest releases of the identified software for a two-year period. These licenses have to be purchased individually as they are needed.
   3. Renew the existing Microsoft Enterprise Agreement (EA) at the proposed discount. This provides the Company with the ability to use the latest releases of the identified software for a three-year period. These licenses are paid for at the same time once a year following a count of the personal computers.

The following table identifies the costs associated with the above options for approximately 597 personal computers (PCs):

	Cost per PC
Do Nothing	$1,420
Select Agreement	$361
Enterprise Agreement	$288

The EA renewal is the least expensive and least administratively burdensome option for Newfoundland Power at this time.

2. **Database and Development software**: This item involves upgrades to the underlying software components that are used by the Company's application systems. These components include database management software and tools used to develop, modify and operate business applications. For 2004, proposed upgrades include:

   - Database management software.
   - Microsoft SQL Server database software.
   - Application development software.

   These upgrades will ensure the Company's business applications continue to function in a stable and reliable manner as well as ensuring an appropriate level of vendor support is sustained. It will provide the Company's technical support staff with more effective tools for operating and supporting the Company's business applications. One example of this would be increased efficiency in responding to operational problems by having the application system automatically notify one of the Company's technical support staff when a problem is detected.

3. **Environment Management software**: This refers to the technology and processes used to develop, configure, test, implement and maintain applications and hardware throughout the Company. For 2004 this includes:

   - Upgrades to the Company's backup and recovery software used to ensure that the Company's business applications and data are effectively retained for business continuity and retrieval of historical information.

   - Upgrades to the Company's workflow application infrastructure used to operate the "Contribution in Aid of Construction" (CIAC) and "Authorization for Change in Payroll" applications.

   Benefits include:

   - Improvements to the reliability and stability of the Company's backup and recovery processes. The software currently used for backup and recovery (for

Windows platforms) was implemented in 1995 and is unable to effectively meet the required backup cycles needed to manage the Company's more than 1 Terabyte (1,000 gigabytes) of information.

- Reduction in costs associated with data corruption or application downtime. Certain backup procedures have failed in the past, requiring the Company to re-run these backup jobs during peak hours (causing overall system performance degradation).

- Consolidation of software used for backing up information from all operating systems used by the Company. Currently, there are different backup and recovery products for the Company's operating systems (OpenVMS, Windows and Tru64 Unix).

- Consolidation of backup and recovery processes, reducing the overall system administration activities (related to having three disparate products at this time).

4. **Application software**: This involves the upgrade of the Company's application software packages, including Microsoft Great Plains and Invensys Avantis.PRO.

   The Microsoft Great Plains upgrade from Version 6.0 to Version 7.0 was initially included in Newfoundland Power's 2003 Capital Budget Application approved by the Board in Order No. P.U. 36 (2002-2003). Microsoft subsequently extended its support of Version 6.0 and Newfoundland Power therefore deferred this major upgrade till 2004. A minor upgrade to Version 6.08 was completed in 2003 at a cost of approximately $78,000. This was a pre-requisite to the Version 7.0 upgrade and was required in 2003 to facilitate improved third party billing procedures.

   The Avantis upgrade is required to meet a contractual obligation related to the initial implementation of the product (in order to maintain support and maintenance).

   Benefits include:

   - Ensuring that corporate applications continue to operate in a stable and reliable manner and avoid the risk of software failure or obsolescence.

   - Additional and enhanced functionality that will add to the Company's overall efficiency without the cost of installing new software. This item will allow Newfoundland Power to avail of newly developed functional capabilities in newer releases of existing application software and reduce or eliminate the need to acquire additional software, or develop manual workarounds.

   - Reduce the dependence on Company specific modifications. With many of the Company's packaged applications, modifications were made during the initial implementation in order to meet specific Company requirements. Performing upgrades often includes enhanced (or new) core functionality that would result in the Company being able to remove the modification from its configuration. For example, with the latest release of Microsoft Great Plains, there are two enhancements that the Company can utilize, eliminating the need for custom modifications and process "workarounds".

5. **SCADA Development Environment**: This item involves the setup of an environment to support ongoing development of the SCADA application used by Newfoundland Power to monitor and control the electrical system. This will involve the purchase and installation of additional software licences and configuration of the environment to support application upgrades and enhancements as well as testing and training. Benefits include:

   - More efficient mechanisms for ensuring the reliability and integrity of the production environment.
   - More opportunities for prototyping and near production testing and training.
   - Ensuring that changes affecting the SCADA system are fully tested before being implemented in the production environment.
   - A more effective process for migrating changes to the production environment.

Project Title:	**Customer Systems Replacement**
Location:	**Various**
Classification:	**Information Systems**
Project Cost:	**$226,000**

Description: This project consists of several enhancements to the Customer Service System ("CSS") that reduce the dependence on the OpenVMS operating system. Through this project, computer programs will be retired from the OpenVMS system in keeping with the findings of the Customer Service System Replacement Analysis (See Volume IV, Information Systems, Appendix 3, Attachment A). The CSS programs being replaced are:

1. **Customer Bill Design, Format and Print:** Currently the layout of the customer bill is programmed as part of the custom developed software application inside the CSS. The process of defining the layout and formatting each bill for printing will be retired from the CSS by utilizing alternative available printing facilities. Other existing printing facilities will be modified to allow for design and formatting of bills without the need for detailed knowledge of a computer programming language.

   Benefits include:

   - Reduced effort in designing and formatting of customer bills, thereby increasing the Company's ability to modify its bill formats, increase customer satisfaction and respond to customer needs. Since the CSS was implemented in 1992, significant changes to the design of the customer bill have not been given priority because of the extensive effort and resulting cost to re-program the bill layout.

   - Reduced dependence on the OpenVMS operating system through the retirement of software.

2. **CSS Customer Letters:** Currently a special version of the WordPerfect word processing software is utilized on the OpenVMS operating system to format and print many customer form letters. This item will retire the current letter format on OpenVMS and the WordPerfect package.

   Benefits include:

   - Reduced effort to design and format a new letter or to revise an existing letter. This is currently a manual process requiring knowledge of computer programming. Use of the new printing facilities will allow the Company to set up and revise letters with minimal technical support (reducing the reliance on specific resources).

- Eliminate the need for a special version of WordPerfect on OpenVMS, further reducing the Company's reliance on OpenVMS.

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3. **CSS Reporting:** This item involves implementation of reporting tools to support ongoing ad-hoc reporting requirements. A number of existing production reports and procedures that extract information from the CSS database will be replaced. A number of these reports involve customer collections.

Benefits include:

- Improved access to customer information.
- Improved collections reporting to provide better control of disconnects, write-offs, and bankruptcies.
- Improved flexibility of customized reports by being able to enter specific parameters rather than have to program the specified requirements.
- Reduced dependence on specific individuals to create reports.
- Reduced dependence on the OpenVMS operating system through the retirement of custom programming code.

Customer Service System

Replacement Analysis

July 16, 2003

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Appendices

Executive Summary

Introduction

The Customer Service System Study as planned for in the Company's 2003 capital program was completed in July of this year. The purpose of this study was to examine whether feasible alternatives to replacement exist that would extend the useful life of the Customer Service System (CSS) while mitigating the risk associated with declining industry support of the OpenVMS operating system.

Background

The CSS performs customer billing and payment processing and supports the Company's customer services activities in the Customer Contact Center and throughout the organization. It is the largest and most complex business software application at Newfoundland Power. The CSS is an internally developed software application (as opposed to a software package) that is now over 11 years old. The application runs on the OpenVMS operating system.

OpenVMS is a software tool that is categorized as a server operating system. It controls computer hardware (i.e. servers) and how the hardware functions. It enables software applications to reside on servers and to utilize capabilities such as processing capacity, memory, connections to networks and storage.

The CSS is a large and complicated system and the minimum duration of any project to replace it is 18 months with more than 24 months from initial planning to a working system being not unreasonable. Given the length of time required to replace the system, judging timing of technical obsolescence is a critical issue. Significant, if not catastrophic, consequences in terms of impact on revenues, costs and customer service will result if the existing system ceases to operate before it can be replaced.

In August 2001 the Company provided the Public Utilities Board with a report that identified the declining support for the OpenVMS operating system as an emerging issue at Newfoundland Power. A copy of the report is provided in Appendix A – PUB OpenVMS Obsolescence Report.

The report outlined the implications of the issue and the Company's plans for replacing OpenVMS based applications. At the time it was anticipated that the CSS would need to be replaced in the three to five year time frame, subject to change based on IT industry developments.

Newfoundland Power's Reassessment of the OpenVMS Situation

What IT industry developments have occurred since 2001?

In May 2002, Hewlett Packard Company (HP) merged with Compaq Computer Corporation, the vendor for the OpenVMS software.

Since this merger, HP has provided a detailed roadmap of future support for the OpenVMS operating system. They have been aggressively promoting the OpenVMS operating system as a viable platform and they plan to continue selling and supporting OpenVMS based computer systems for at least another 8 years. HP has sent a personalized letter to Newfoundland Power reiterating their roadmap and support plans.

In addition to OpenVMS, the CSS relies on database software from Oracle Corporation and software development languages from Cognos. The particular software tools used by Newfoundland Power have features that are dependent on the OpenVMS operating system. Both Oracle and Cognos have publicly announced that they will continue to support their tools according to HP's roadmap for OpenVMS.

Is OpenVMS still in decline?

The number of Independent Software Vendors (ISVs) developing and marketing business applications for an operating system is a key indicator of the health of the operating system. Although HP has been very aggressive in showing their long-term commitment to OpenVMS, leading IT industry analysts Gartner Group[1] continue to feel that the number of ISVs that are providing products that run on the OpenVMS is dropping and will continue to drop.

There continues to be little or no coverage of OpenVMS at conventions, conferences and trade shows. As well there continues to be no local college or university academic programs that focus on OpenVMS or dependent technologies.

Other signs of decline previously experienced by Newfoundland Power were slower response to support calls, waiting longer to have software bugs fixed, and very limited access to experienced OpenVMS staff across Canada. Although these concerns are still present, Newfoundland Power has already replaced a number of OpenVMS based systems and therefore the amount of support and assistance required has been reduced. As well, the remaining OpenVMS

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand technology and drive business growth. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 80 locations worldwide.

dependent applications have been very stable. As a result, there have been few support calls and little need for assistance from OpenVMS qualified resources.

The question continues to be not whether to migrate but when. The Gartner Group's view has moderated somewhat on the timing of migration and they are currently of the opinion that … "OpenVMS is not a sustainable strategy other than for specific and short-term tactical needs or budget needs".

Newfoundland Power's Plan for Replacing the CSS

Newfoundland Power conducted a review of how well the existing CSS is supporting efficient delivery of customer service. It has been determined that although there are a number of opportunities to add enhancements to the CSS, none of the opportunities individually, or as a whole, would require replacement of major portions or all of the CSS. At the highest level the very high customer satisfaction levels and general reduction in operating costs per customer over the past number of years are indicators the existing CSS is meeting the needs of the Company.

At this time any consideration for replacing the CSS is related to the continued decline of the OpenVMS platform and as a result of functional obsolescence.

What are the options?

The Company has identified a number of courses of action. One option is to replace the CSS by purchasing and implementing a software package that is not dependent on the OpenVMS operating system. This may have additional benefits of allowing the Company to improve customer service and obtain efficiencies through the utilization of new functions and features not present in the existing CSS.

As a result of consulting with utility industry analysts, customer service system experts and customer service system software vendors, Newfoundland Power estimates a project to implement a new software package would be eighteen to twenty-four months in duration at a cost in excess of $10 million.

A second alternative is to keep the existing CSS as it is today and migrate the underlying software to a new operating system. Newfoundland Power asked a number of vendors who are experienced at migrating OpenVMS dependent software to new operating system platforms to complete assessments of the approach and costs to migrate the CSS. One of these vendors (Sector7) is a market leader at completing technology migrations. As well the Company asked the assistance of our current major technology suppliers, HP and Microsoft, to identify alternative approaches and costs for a migration. As a result of these assessments and advice from our major technology suppliers Newfoundland

Power estimates it would take eighteen to twenty-four months to migrate the CSS application to a new operating system at the cost of at least $6 million.

A third alternative is to continue to run the CSS on the OpenVMS platform and monitor industry developments and HP's progress on their support roadmap. The Company does not expect to experience any major increases in costs to continue running the CSS on the OpenVMS operating system in the next several years. Although one of the signals of declining support is increased support costs (e.g. to obtain and retain OpenVMS expertise, one of a kind hardware and software licensing and maintenance costs etc.), there are several employees who have OpenVMS expertise and the support costs for hardware and software are not expected to be significantly more expensive than similar costs for a new or migrated application, at least, in the next several years. A key benefit of this alternative is that the existing system will continue to be used to support delivery of service to customers and will not be prematurely replaced with respect to it's functional lifespan.

What will we do?

Newfoundland Power feels the best alternative now is to continue to run the CSS on the OpenVMS operating system, be vigilant to monitor industry developments and react accordingly and reassess the OpenVMS situation again no later than 2006.

It is Newfoundland Power's view that there is acceptable risk associated with the short and medium term viability of the OpenVMS operating system. HP, Oracle and Cognos are committed to supporting OpenVMS over the next number of years. Given the large number of their customers depending on these companies' software, the period of time allowed to remove applications from OpenVMS would be measured in multiple years should these companies unexpectedly announce plans for no longer supporting their OpenVMS software. Accordingly, in our view there is little or no risk that the CSS will be rendered inoperable as a result of OpenVMS obsolescence issues within the next three years.

Finally, in the review of available replacement software packages, the Company did not see functionality that would provide such an advance in customer service or introduce efficiencies to justify a very large implementation project and an investment of more than $10 million at this time.

What are the next steps for the CSS?

In the next several years the Company will continue to enhance the CSS where efficiencies and customer service improvements may be realized and can be justified. The fact that the CSS may be replaced some time after 2006 will be taken into account when justifying such projects. In the course of completing enhancements the Company will seek to identify approaches to reduce dependence on the OpenVMS operating system. Reduced dependence will be an added benefit to any such project if realized.

All future enhancements to the CSS will be rigorously reviewed and if any new software modules are developed, they will be developed using toolsets that are not dependent on OpenVMS. As well, the Company will look for opportunities to buy “bolt-on” software packages or utilize capabilities of existing non-OpenVMS dependent systems. For example, in 2004 the Company plans to enhance the CSS with a more flexible and efficient bill design and print function and a new customer letter design and print function, utilizing the capabilities of the existing printing facilities that do not reside on OpenVMS. This will allow for retirement of a significant portion of the CSS software that currently formats and prepares customer bills and letters, while improving customers service and obtaining efficiencies. Finally in 2004 the Company plans to utilize non-OpenVMS related technology for Customer Service reports. As new reports are developed and existing reports are revised, OpenVMS dependent report programs will be retired.

By gradually reducing dependence on OpenVMS the Company will be well positioned to minimize migration costs if a migration is required. As well, if a package replacement becomes the wisest future option, the number of modules purchased may be minimized.

To obtain further external validation of the approach and findings of this CSS Replacement Study the Company commissioned Meta Group[2] to review a draft of this report and provide their professional opinion. Meta Group’s summary conclusion as a result of their review is as follows: “In conclusion we jointly concur with the findings and recommendations in the aforementioned Newfoundland Power Customer Service System Replacement Analysis Study.” A copy of their review is provided in Appendix B – META Group CSS Replacement Study Review.

Update of Plans for Other OpenVMS Based Systems

Are we on track?

The company’s plan, as outlined in the report provided in 2001, remains to decommission the OpenVMS environment in an orderly and cost effective fashion through the normal replacement of applications.

In 2002 all Business Support Systems including Human Resources, Financial, Payroll and Material Management systems were replaced as scheduled.

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[2] META Group is a research and advisory firm that helps more than 3,300 businesses in 40 countries understand technology and drive business growth. Unlike Gartner and other advisory firms, META Group also provides vertical expertise and coverage of the IT solutions for industries such as energy and utilities.

As a result of application replacements to-date the number of OpenVMS based servers supporting applications has been reduced from five down to three. The only OpenVMS based servers in use today are those required to support the remaining Operations and Engineering applications, CSS and CSS dependent applications and the Problem Call Logging application.

In the last half of 2003, OpenVMS based applications to support the Operations and Engineering areas of the business will be replaced as planned.

The Problem Call Logging System, currently supporting Outage Management, is an in-house developed OpenVMS based application. This application will be migrated to the Windows operating system and will receive significant functional enhancements as a result of the Outage Management project being completed in 2003.

By end of 2003, the only OpenVMS based applications still operating within the Company will be the CSS and CSS dependent applications.

Summary

The Company is continuing to treat the issue of declining support for the OpenVMS operating system very seriously. An overly aggressive response to this risk could result in unnecessary increases in costs to support the customer service function, reduce customer service levels and introduce inefficiencies while employees are distracted with unnecessary changes to the systems supporting the Customer Service function. However, ignoring this risk until it is too late to react effectively will result in exorbitant costs to resolve a crisis, reduced revenues and loss of ability to provide customers with even basic services.

The Company has weighed the high costs of replacement or migration of the CSS against the risks (and therefore potential high costs) of keeping the CSS on the OpenVMS platform. The short to medium term risk of loss of support of OpenVMS is minimal. The Company will continue to run the CSS on OpenVMS for the next several years while reducing dependence where possible and monitoring industry development and acting accordingly.

For all other OpenVMS dependent applications, the plans to remove applications from the OpenVMS operating system are proceeding as expected.

Introduction

1. Purpose of CSS Replacement Analysis

The purpose of this analysis is to assess the functional and technical health of the CSS and make recommendations regarding timing and approach to replacement. The long-term viability of the OpenVMS platform upon which the CSS resides is a current concern, which will be assessed through this analysis.

2. Background

The current Customer Service System was originally implemented in two phases with the first implementation in November 1990 and the final release in June 1992. The system was expected to support the Company's Customer Service business requirements for 20 years. In 1998 a major technical environment refurbishment was completed as a result of Anderson Consulting (now called Accenture) discontinuing their support for the proprietary Install/1 product used to develop and operate the online system.

Given the system is 11 to 12 years old, and therefore past half of it's expected useful life, it is prudent to review how well the system is supporting the Customer Service function and recommend a strategy for future enhancements or replacement as required.

Why is OpenVMS an Issue?

In 1998 Compaq Computers acquired Digital Equipment Corporation (the owner of the OpenVMS Operating System) and merged the companies. As a result of this merger, industry analysts questioned the long-term viability of the OpenVMS operating system to be the operating system of choice to support business software applications. Since that time, Newfoundland Power has been monitoring the concern and initially made the PUB aware of the issue in 2000. In 2001 the Company delivered a report to the PUB identifying the issue and outlining the Company's plans for addressing it. The report can be found in Appendix A - PUB OpenVMS Obsolescence Report .

Given the CSS is the largest corporate application in the Company and it runs exclusively on the OpenVMS platform, the life expectancy of the CSS is directly related to the issue of the life expectancy of the OpenVMS platform.

Technology Background

Advances in technology have continued in dramatic fashion since the CSS was initially developed in 1992. Computing speeds have grown exponentially, computer memory capacity has grown and data storage capacity has seen amazing increases along with major cost reductions. With these advances and with the advent of the Internet and associated Web technologies the way in which software applications are developed, deployed and managed continues to change and therefore the tools to support these activities have also changed. The Technical Migration of the CSS in 1998 is a relevant example of this. This $2 million project involved converting the DBMS from Rdb to Oracle and converting the online transaction software to a new development language. This migration was necessary due to the vendor no longer supporting the online transaction processing software used by the CSS.

Functional Background

Since the CSS was implemented in 1992 the Company centralized the Customer Service function, implemented and subsequently terminated bi-monthly meter reading, implemented multiple EPP options, implemented Pre-authorized payment plans, implemented world class customer contact center technology including IVR, increased support for Outage Management by linking customer premises to distribution feeder and implemented OMR enabled meter reading. All of these changes and improvements have been supported and in many cases enabled by the CSS.

The CSS continues to be enhanced and maintained to support improved customer service and cost reduction opportunities.

3. Overview of the Approach

The approach taken for this analysis includes:

- Complete an internal assessment of the functional and technical health of the CSS.
- Identify the long-term functional requirements for the CSS and adequate technology to support these requirements
- Examine the external environment with respect to the experience of similar and local utilities.
- Reassess the long-term viability of the OpenVMS platform, obtaining information from our major technology partners, industry experts and the market in general.
- Obtain an understanding of Customer Information System (CIS) package offerings with respect to functional fit and cost.
- Obtain an understanding of CIS extensions or “bolt-on” applications with respect to type, functional fit and cost.
- Review what industry experts are saying about CIS for electric utilities.
- Review what industry experts are saying about current technologies used to maintain the CSS.
- Identify Technical Migration alternatives and obtain cost estimates and other significant demographics (e.g. length of project, fit to target technology environment, etc.).
- Among “Package Purchase”, “Technical Migration” and “Stay on OpenVMS” alternatives, recommend a future strategy and provide plans and timelines for the recommended strategy.

Assessment of Internal and External Environment

1. Current CSS Functional Assessment Summary

1.1. Customer Service Function Description

The Corporate Communications, Customer Service and Safety Department (“the Department”) at Newfoundland Power has a diverse range of responsibilities including corporate, functional and operational responsibility for delivering award winning Customer Service. The Department performs those business functions required to deal directly with customers (e.g., inquiries and service requests), the collection of meter readings, billing, the management of special programs, payment processing as well as credit and collections.

1.2. Customer Service System Description

Developed in-house, with the assistance of a major consulting company (Accenture), the Customer Service System (CSS) provides the Company’s primary accounts receivable and direct customer billing for electrical sales. It consists of Meter Reading, Pre-billing, Billing, Cash Processing, Pending Work Queues, Credit and Collections, Accounts Receivable Maintenance, Service Orders, System Controls and Financial Controls. A more detailed description can be found in Appendix C - Customer Service System Functional Description.

1.3. CSS Functional Assessment

On a quarterly basis, the Company conducts a survey to determine its approval rating amongst its customers. The approval rating for the last three years has been on average 90% (89%, 90% and 91%). This gives NP a strong indication there are no major customer service issues driving a replacement of CSS.

However, as evidenced by change requests, notes and the discussion given below, there are gaps and weaknesses within the CSS. The question to be asked is how important are the changes to “doing” our business. Are they simply something nice to have or are they necessary to the efficient operation of the business? Does the value they add outweigh the cost of making the change? Do these changes become the economic driver for replacing the CSS?

Analysis

Interviews were conducted with the CSS users and stakeholders to determine the level of need. This review included all levels of positions, from clerical staff to Directors, and users external to the Customer Service Department. In addition to interviews with staff, existing documentation regarding outstanding issues were evaluated as were change requests identified during user acceptance testing and the original implementation in 1992. Together this review yielded approximately 220 potential functional changes or enhancements.

This list of potential changes were roughly prioritized based on a very high level review of expected benefits. As well an order of magnitude of effort (High, Medium and Low) was estimated to facilitate planning.

Approximately 21 % of the 220 potential changes identified were ranked as a "High" priority. The majority of these potential changes impact the Billing and Credit functional areas. It is expected these high priority changes alone will require approximately 18 years of programming effort (does not include implementation effort or user involvement for design and testing.). One example of a high priority change opportunity, is to implement customer service and efficiency improvements to the Equal Payment Plan procedures.

Although the number and associated effort of potential changes is significant, the nature of the outstanding changes reflects normal system evolutionary requirements to improve customer service or realize efficiencies. None of the potential changes reflect a dramatic change in business requirements. The CSS is adequately meeting the need to support the Customer Service function.

2. Current CSS Technology Assessment Summary

2.1. Information Services Function Description

The Information Services Department consists of approximately forty staff, operating out of a centralized location at Head Office in St. John's. The group is divided almost equally between Operations/Infrastructure and Solutions Delivery. A substantial number of the Company's current enterprise applications run on the Compaq Alpha/OpenVMS platform; other applications and all collaborative, workgroup and personal computing applications utilize the Microsoft NT/Windows 2000/Exchange/Office environment.

Over the past five years the Company has established several processes within the Information Services function. These include:

- Help Desk and Support Call Escalation
- Change Management
- Desktop Renewal
- Disaster Recovery
- Solutions Delivery
- Application Support and Maintenance

2.2. CSS Technology Description

Customer Service System Technical Architecture

The technical architecture of the CSS is described within the context of:

- Online Environment/User Interface
- Batch Environment
- Data Architecture
- Security Architecture
- Reporting Environment
- Development Environment
- Hardware Infrastructure

Detailed descriptions of the technical architecture within these areas can be found in
Appendix D – Customer Service System Technical Description.

Customer Service System Application Integration

The CSS application and the Company's other custom developed and third party applications are integrated. As well, there is an exchange of information with outside agencies.

At the present time, the Company does not use middleware integration products. Most of the integrations are custom developed, batch oriented, point to point data file transfers with upload and download procedures, with the exception being direct database access in certain applications to and from the CSS.

An overview of the various application integrations can be found in Appendix E – CSS Application Integration Description.

2.3. CSS Technology Assessment

Strengths

The following are the major strengths of the CSS technology environment:

1. Response time for most functions in the online environment is now sub-second. As well there are three ways of navigating around the system, which provides a lot of flexibility for different situations and user preferences. The ability to have multiple conversation "threads" open at the same time (called the suspend/resume function) allows for increased productivity by contact center staff.
2. A large portion of the batch processing software is written in COBOL, a language that continues to be in heavy use worldwide and whose future is very stable.
3. The batch-processing environment is heavily tuned for performance and integrity and is therefore very stable. After hours callouts have become rare and usually are related to human error.
4. The data model for CSS is fully documented and very well normalized to support the online and batch processing. The database management system (DBMS) is from a leading vendor (Oracle) and there are deep in-house skills for supporting the database environment. Overall security features are strong with multi-layered security (OS, DBMS and Application) that work well together.
5. The hardware platform and operating system are highly secure, scalable and stable.
6. The development environment is stable and very rich in functionality with very mature environment management procedures and various in-house tools and procedures to support development and testing.

7. The disaster recovery environment is an exact copy of production with up to date procedures in place.

Weaknesses

The following are the major weaknesses of the CSS technology architecture and environment:

1. The operating system platform of OpenVMS will not be a viable platform over the long term.
2. Legacy development tools (Axiant, Powerhouse Quiz and QTP) are being used for programming the online system, most reporting and some core batch processing. Skills for these legacy tool sets have to be maintained in-house but are not required for any of the new systems.
3. There is no user-friendly reporting tool being used (currently using a legacy tool – Powerhouse Quiz) and the data model, although optimized for the online system and batch processing, does not adequately support reporting requirements.
4. There are a huge number of activities requiring operator attention when running nightly batch processes. There are many opportunities to make batch operations much more efficient and less operator dependent. The batch window has less than optimal contingency for having the system available at 8:00 am as a result of inefficient reporting processes and no separate reporting environment.
5. The architecture of the batch-processing environment is extremely complicated and is very inefficient, causing operations problems and difficult recovery when things go wrong.
6. With the current online client/server topology, desktop deployments tend to be complicated and time-consuming.
7. Although we are utilizing a leading DBMS vendor (Oracle) the DBMS is not as well supported on the OpenVMS platform as others and the availability of "OpenVMS specific" deep DBMS skills is problematic. This causes problems with lengthy and costly upgrades, unavailable features and longer times to receive DBMS bug fixes.
8. As Information Services department and Customer Service department staff move onto other technologies, CSS specific skills and knowledge are not being retained. In-depth knowledge rests in a small number of individuals.

Overall the most significant technology issues associated with the CSS are the reliance on the OpenVMS platform and significant dependence on the legacy software development tools of Powerhouse and Axiant.

3. Other Utilities

3.1. Utility Survey Summary

Survey Description

A survey of other Canadian utilities was conducted in the course of this analysis. The purpose of the survey was to gain an understanding of the demographics of CIS systems in use at other Canadian utilities (major features, whether packages or in-house systems, age of systems, technology platform etc.) and the past experience and future plans of other utilities with respect to their Customer Information Systems. An understanding of the experiences of other Canadian utilities provides an inexpensive way of learning about potential pitfalls before we proceed on any path.

Most utilities were included on the basis of whether they were electric utilities and of a similar size to Newfoundland Power. The CEA membership directory was used to identify potential survey candidates. Two other Canadian Fortis sister utilities also were included, as were a small number of smaller and larger utilities to round out the list.

Each utility was contacted prior to sending an actual questionnaire to determine interest in participation and to obtain contact information. The identified contact was sent a questionnaire via e-mail and was followed up with a phone call about week after they received the survey.

Fourteen utilities initially were identified and contacted of which 12 utilities actually received the questionnaire.

The Questionnaire Template is provided in Appendix F - Utility Survey Description.

Survey Results

The response was poor and although initial contacts indicated the utility would respond, eight utilities later decided not to participate. The initial contacts were followed up by email and telephone calls in an attempt to obtain a response. Only four utilities completed the survey in full and one submitted a partial response. Telephone follow up indicated the remaining utilities decided not to respond to the information request due to the state of the utility industry, specifically the deregulation of the industry in Alberta and Ontario (competition and confidentiality).

Given the low number of responses, the usefulness of the information received is limited. The following is a brief summary:

- Software packages are being used with most utilities utilizing specific specialized in-house developed applications to complement the package software.
- All utilities that responded have on-site cashier facilities for bill payment and most had authorized agents collect payments on their behalf as well.
- The Microsoft Windows environment is being utilized as a platform for the CIS for at least one utility.

3.2. Newfoundland and Labrador Hydro

Newfoundland and Labrador Hydro ("Hydro") serves over 30,000 mostly rural customers on the island of Newfoundland and in Labrador.

Various contacts with Hydro have been made in the past year to identify ways of achieving common efficiencies within Meter Reading and other Customer Service functions.

In May 2003 Dale Batstone (Information Services - Project Leader), John Pope (Information Services - Technology Specialist) and Linda Moores (Customer Service – Customer Accounting Specialist) met with Hydro's Glenn Mitchell (Rates & Financial Planning), Donna Smith (Rates & Financial Planning) and Janice Sears (Information Services) to specifically share experiences and plans regarding their respective Customer Information Systems.

Historically Newfoundland Power hosted Hydro's bill calculation and print processing until Hydro implemented it's own system just prior to Y2K. (In the 1970s, Newfoundland Power and Hydro's systems were almost identical and used the same software system.) To meet Y2K compliancy, Hydro implemented a J.D. Edwards Enterprise Resource Planning system for all of their major business applications (Financial, Materials Management, Work Management, CIS, etc.).

The CIS module is a separate module but is heavily integrated with all of the other modules within the ERP solution.

The following are a list of "points" resulting from the discussion:

- In terms of business requirements, the Rates and Financial Planning group are reasonably satisfied with the system's functionality.

- The current version of the software Hydro is using is a mainframe-based solution relying on older technology such as the RPG development language. This is a “green screen” or text-based system.
- The latest available version of the J. D. Edwards ERP (One World) is browser based.
- The CIS module can be purchased separately; however, many of the benefits associated with it are related to tight integration with the other J.D. Edwards packages, particularly Finance and Work Management.
- AMX International markets and implements a newer up-to-date version of Hydro’s CIS, called Utiligy.
- The future of their CIS is tied directly to the future of their investment in the whole J. D. Edwards ERP portfolio

Based on the level of integration required to realize significant benefits and the older technology being utilized, Newfoundland Power will not pursue Hydro’s CIS as a replacement option.

However further discussion should continue with Hydro on shared opportunities regarding meter reading, cash processing, bill print and other potential “bolt-on” scenarios.

Objectives and Vision

The purpose of this section is to identify business and technology strategies and plans which will influence decision making regarding the replacement or ongoing maintenance of the CSS.

1. Business Objectives

The high-level business objectives associated with the Customer Service function are:

- Continue to optimize customer service costs through fine-tuning existing business processes to obtain efficiencies.
- Continue to provide excellence in customer service through timely delivery of cost effective customer service programs that match the demands of our customers.

2. Business Vision

2.1. Customer Service Vision

Each section of Customer Service has determined its future direction. Frequently, this path crosses functional areas affecting other sections.

<u>Meter Reading:</u>

In response to market trends, Newfoundland Power will leverage the current Handheld Meter Reading System and may continue its pursuit and utilization of Automated Meter Reading (AMR) technologies.

- Continued adoption of and investment in new AMR technologies could impact the current meter reading workforce, both by reducing the number of positions and demanding a new technical competence and/or different work skills.
- As the Meter Reader's daily work reduces, more time will be available for other duties. The Company will continue to "in-source" work that complements the meter reader's position from groups internal and external to the Company. In the past this has included completing meter changes in the field.

- AMR will reduce the need for additional field visits required to obtain meter readings at inaccessible and unsafe locations. In addition to obtaining efficiencies, this may reduce risk of injury to employees.

Customer Payment:

Customers increasingly will rely more and more upon electronic payment options as they become available.

- New customers are more likely to use electronic payment options than their parents (Newfoundland Power's current in-person customers).
- The take up rate for electronic payment options (bank payments, telephone payments) has increased over the past number of years. This trend will continue.
- In response to increasing cost pressures, it may be more economical in the short term to offer in-person payment facilities at sites other than NP offices. In the long term, maintaining in-person cash facilities in all the Area Offices may not be cost justified.
- Current hardware issues make it necessary to replace the front-end cash register systems within the next year or two. The present assumption is in-person cash facilities will be, as a minimum, available in major centers.

Billing:

Billing within CSS will become more complex over time.

- As rates become more complicated, training and retention of this information by staff will become an issue. This will change the knowledge and skill levels of certain positions within the clerical group.

Credit and Collections

Credit and Collections will rely more on technology to communicate with customers and will be impacted by technology changes to other areas of the Company.

- Technology advancements in other areas of the Company, including Meter Reading, Outage Management and Engineering/Operations, may change credit workflows and work processes. For example, advances in Automated Meter Reading may reduce or eliminate the need for field visits to disconnect service.
- Field collections staff may require a new technical skill set.

- Utilization of web and other new technology should decrease the number of field visits required by collections staff.
- New reporting tools will allow management staff to focus credit and collections resources as needed.
- Collection action will be customized according to customer profiles and risk factors.

Customer Contact Center/Customer Service:

The Customer Contact Center will utilize the web and new contact technologies to meet its customer service objectives. Programs and service levels will be weighed against increased operating costs.

- With operating costs likely to increase over the next few years, it is unlikely the Customer Contact Center will expand its operating hours.
- To respond to low demand and to offset increasing budgetary pressures, the Customer Contact Center may withdraw in person service during off peak hours, e.g. after 6 pm.
- Again, due to high operating costs, the focus will be on providing customers with direct access to the information they need to conduct their own business (e.g., request for service, EPP, etc.) or answer their own queries (e.g., high bill complaints). The Web and its technologies will become more and more important.
- Access to on-line services will become more important to rural Newfoundland over time.
- Traditional methods of contact, e.g. phone calls, will decline over time and WEB technology, such as on-line chat rooms, will be used to communicate with our customers.
- Technology advancements in other areas of the Company, including Meter Reading, Outage Management and Engineering/Operations, may move work previously done by field staff to Customer Services staff.
- As the Company moves from a Customer Call Center to a Customer Contact Center for the whole company, staff will require a new skill set, largely technical.

- The Customer Contact Center will take advantage of existing and new Customer Contact Center technology, e.g., voice recognition of telephone numbers.

- Technology likely will be utilized to provide alternate work arrangements, such as work from home and remote agents. This may improve customer service, eg., respond to certain enquiries faster, such as power outage calls. This will change the way supervisors interact with staff and how staff interacts with co-workers.

General:

The role and focus of supervisory positions is changing from completing tasks to managing employees and the work performed. Today, management staff rely heavily on exception and ad hoc reporting to identify issues requiring their attention. As technology advances and the capabilities for audit and self-assessment by clerical staff become realized, supervisors will be better equipped to do the work required of them.

3. Technology Vision

3.1. IT Principles

The following general information technology principles are applied to all major technology investments:

- Partner with leading vendors
- Minimize the diversity of installed technologies
- Buy rather than build technology
- Consider the full cost of the product over it's lifespan
- Invest in proven technologies

The following more specific principles will be used to help guide the definition of the target technology architecture for the CSS and will guide decision making on any replacement or migration project for the CSS:

- Continue to ensure effective and adequate levels of security (network, application and data)
- Continue to improve integration between existing applications and external suppliers and customers; strive to reduce duplication and inconsistency
- Improve access to information by effectively utilizing technologies for improved document and content management, information portals, ad hoc reporting, and online analytical reporting
- Continue to seek efficiency improvements in how we work through the automation of workflow activities (approval processes and notification)

3.2. IT Solutions Acquisition and Development Strategy

IT Solutions Strategy

Moving forward, Newfoundland Power will reduce reliance on niche technology platforms, application and software vendors. To date, Newfoundland Power has standardized its desktops on the Microsoft environment and has made significant investment in Microsoft technologies. This strategy is expected to continue until other platforms have matured (e.g. Linux) and have proven leadership in cost effectiveness and reliability to justify a switch in operating platform of choice.

Based on this strategy, all new in-house developed applications will be developed for the Microsoft Windows platform. As a result, we will:

- Continue to restrain new investments on the OpenVMS platform and in the Cognos Powerhouse/Axiant AD toolset.
- In case an existing Powerhouse/Axiant application requires modification, each situation will be analyzed to determine the feasibility

of utilizing COBOL, DBMS Stored Procedures, Impromptu or Microsoft VB .NET.

Where an existing application resides on a different platform (such as CSS on OpenVMS) the following strategy will apply:

- New modules or purchased modules will be developed to run on a platform other than OpenVMS.
- Where integrations are required the integration will be developed on the target platform (vs. integration code developed on OpenVMS to send to a Microsoft Windows platform).
- When major modifications are made to the existing application and the functional architecture and cohesiveness of the application is not compromised, new and/or revised modules will be developed to run on a platform other than the OpenVMS platform (e.g. develop a "bolt-on" for bill print). However, generally minor modifications and enhancements will continue to be made without migration to the new platform
- Cease utilizing proprietary OpenVMS DCL and the RMS file structure system. We will only utilize such features when they primarily support the core application code. (i.e. Changes to CSS core sub-systems)

The information systems delivery group will continue to maintain its existing application development processes (specification delivery, unit, function and system and integration testing).

Corporate Applications Integration Strategy

The following strategies will be used with respect to integrating corporate applications:

- We will continue to seek improved integration with Microsoft office products (Word, Outlook, Excel).

- We will begin to utilize web services to integrate data.

- Where integrations are required for applications/data residing on other than the Microsoft Platform, these integration procedures will be developed to run primarily on the Microsoft Windows platform. This will insure the investment is not lost when the application is eventually migrated to the Microsoft platform.

- When evaluating a packaged software application we will ensure it supports the various forms of integration. We will ensure the application vendor offers application programming interfaces, adapters, import and export tools and/or supports the use of XML.

CSS Specific Application Integration Strategy

The Company will continue to improve and build on automated CSS integrations with internal company applications. These integrations will be more important as we utilize third party software to enhance the CSS functionality:

The CSS will be required to integrate with the Asset Management System, (Avantis.PRO) particularly once customer's meters are tracked thru the Asset Management System and when customer driven work is managed via the work order functionality of this application.

The CSS will be required to integrate with 'bolt on' CIS packages and other external facilities such as design and print bill software and call centre computer telephony integration software.

The Company will expand the level of integration between the CSS and our Outage Management systems to improve crew response using predictive information regarding the source of an outage based on the location of affected customers.

The Company will continue to expand our use of electronic data transfer methods for the contact to and from our customers. (e.g. interactive voice response, electronic bill presentment and so forth)

Replacement Options Analysis

There are five basic approaches for managing the CSS into the future:

1. Stay on OpenVMS
2. Package Purchase
3. Outsourcing
4. Legacy Extension and Bolt-on Applications
5. Technical Migration

This section describes the most viable alternative within each approach and provides an analysis of the feasibility and cost of each.

1. Stay on OpenVMS

1.1. Description of Alternative

This alternative involves continuing to maintain the “core” Customer Service System on the OpenVMS platform in the short to medium term (2 to 5 years).

However, rather than maintain the system exactly at it is today, this alternative also involves strategies and plans to gradually reduce dependence on the OpenVMS platform through code retirement and modular replacement through the normal course of functional enhancements and maintenance and technology governance.

1.2. Summary of Research

Xwave Report – May 2002

In the spring of 2002 Newfoundland Power commissioned Xwave to complete an in-depth analysis of the OpenVMS issue. A full copy of the report can be found in Appendix G - OpenVMS Research Project Xwave Report.

The research indicated that while OpenVMS was viewed as reliable and stable, the combination of a number of significant factors would limit the potential for OpenVMS to be a mainstream and therefore long-term viable operating system. These factors impact Newfoundland Power’s assessment of the risks associated with future dependence on the OpenVMS operating system. These factors include:

- *Market Share:* Sales revenues and shipments for OpenVMS are diminishing while Windows and UNIX systems are gaining market share.

- *ISVs View of OpenVMS:* Major Independent Software Vendors (ISVs) such as Oracle, have begun to relegate OpenVMS to a Tier 2 platform status, resulting in potential delays in the release of new versions and fixes of ISV software for the OpenVMS operating system.
- *Vendor Technology Roadmap:* Hewlett Packard has committed to sell AlphaServer technology which run OpenVMS until 2006. It has stated that it will continue beyond that date only if the demand is present.
- *Product Availability:* The specific AlphaServer 4100 model used by Newfoundland Power is no longer sold by Hewlett Packard.
- *Replacement Parts Availability:* Replacement components for the AlphaServer 4100 model will become increasingly difficult to obtain.
- *Support Requirements:* Overall less support effort will be required to support a Windows based infrastructure for the CSS vs. the existing OpenVMS based infrastructure.
- *Access to Training:* Training courses for OpenVMS are difficult to obtain without having to travel outside Canada. Due to the low interest generated for OpenVMS training, courses are not regularly scheduled in Canada.
- *Access to OpenVMS Skills:* People with OpenVMS skills are becoming harder to obtain. Graduates from post secondary institutions are entering the job market with little or no OpenVMS experience. Many, however, have had exposure to Windows and UNIX environments.
- *Alternate Environments:* Windows and UNIX platforms have become more accepted by the IT industry. While there is a consensus that OpenVMS is an available and reliable operating system, Windows and UNIX have gained enough momentum to further erode the OpenVMS future.

As a result of these factors, Xwave recommended Newfoundland Power migrate away from the OpenVMS operating system environment and begin deploying its current OpenVMS based applications onto other operating systems.

Industry Research

In October 2002 Gartner issued a research white paper entitled “The Case for OpenVMS: Should You Migrate?”

Significant points from this research article relevant to Newfoundland Power’s situation are:

- For OpenVMS users running custom written code as opposed to software packages (CSS is 100% custom written code), those IS organizations have the flexibility to await the outcome of HP’s migration to the Itanium server (no earlier than 2005).
- IS organizations should be prepared to assess costs of replacing OpenVMS dependent systems via package purchase or code migration to another platform.
- IS organizations should ensure custom code that will eventually be migrated to a new platform is well documented
- All further development on the OpenVMS platform should be “restrained”.
- OpenVMS specific skills will become increasingly difficult to keep and to find.
- Gartner is pleasantly surprised by HP’s development of a detailed roadmap for OpenVMS. “OpenVMS users may feel more breathing room, but they must still remain alert to the roadmap’s progress.”

A copy of this white paper is provided in Appendix H - Gartner Research Note: The Case for OpenVMS: Should You Migrate?

HP’s Commitment to OpenVMS

Every two to three months HP issues roadmap updates regarding the future of the OpenVMS platform.

HP has provided comprehensive information regarding short term upgrade paths and continued functional enhancement improvements and support commitments for database management systems, storage systems, backup systems, networking features, security features, e-business integration and system management tools on the OpenVMS operating system.

The following summarizes the significant points from the most recent roadmap update received from HP in April 2003:

- The HP Alpha Server technology running OpenVMS will continue to be sold until 2006, with support until at least 2011.
- In addition to being available on Alpha Server hardware, the OpenVMS operating system will be available on the latest hardware technology being sold by HP (Itanium), in 2005. As no statement is being made for no longer selling or supporting OpenVMS on Itanium based servers any time in the foreseeable future, it is conceivable that OpenVMS will be available indefinitely.
- HP has provided a portability roadmap (OpenVMS features added to map more closely to Unix operating system features) from the OpenVMS to the market loading Unix platform for now til 2006.

A copy of the most recent roadmap update provided by HP is found in Appendix I - HP OpenVMS Rolling Roadmaps.

Although OpenVMS today only runs on Alpha Hardware servers, HP's roadmap for future operating system deployment is that one type of hardware server (Itanium) will be able to run different operating systems. In effect, OpenVMS will be able to be run on the same hardware that is supporting a Windows platform. This will help reduce risk in the long-term associated with maintaining OpenVMS based applications on aging hardware technology (reliability of hardware, availability of spare parts etc.).

In May 2003, HP provided Newfoundland Power a personalized letter outlining their commitment to OpenVMS and their roadmap for future enhancements and support. The letter reiterates that OpenVMS on Alpha Servers will continue to be supported until at least 2011 and that OpenVMS will be migrated to a newer technology hardware system (Itanium) and sold and supported on that hardware platform. A copy of the letter is included in Appendix J – HP OpenVMS Commitment Letter

HP has provided Newfoundland Power with numerous client testimonials, executive presentations and other white papers supporting the health of the OpenVMS environment, stating HP's commitment to OpenVMS and praising the stability and functionality of the operating system.

HP Technology Assessment Recommendations

In February 2003 Newfoundland Power requested HP to assist in assessing the various options for replacement of the CSS. Newfoundland Power provided HP with a summary of the technology issues, a functional and technical description of the CSS and a description of the target technology environment for the CSS. As well, HP conducted a half-day conference workshop with Newfoundland Power to collect information regarding the CSS. In April 2003 HP responded with a high level assessment report. This report is provided in Appendix K - HP CSS Applications Options Review.

Upon receipt of the report Newfoundland Power requested a deeper analysis of technical migration alternatives and as a result HP completed a second assessment which is described in Section 4, Technical Migration.

However, the following is a summary of the recommendations of the initial report with respect to staying on the OpenVMS platform:

- Adopt newer industry standard tool-sets such as .Net, XML and Java when developing new modules or integrating with the CSS. Utilizing the latest technology toolsets when maintaining and enhancing the CSS will gradually reduce dependence on the OpenVMS platform and leverage the skill sets already being used on the other non-OpenVMS based applications.

- Implement cross-platform management tools such as batch scheduling and back-up/recovery software. If and when there is a decision to migrate the application to another operating system then there will be significantly reduced effort associated with migration of batch processing procedures.

Oracle Commitment

Oracle is committed to maintaining and supporting the DBMS on OpenVMS according to HP's roadmap as evidenced from Oracle's statement of commitment on HP's official website. The following is a quote from the web site: "Oracle has a long and successful history of delivering enterprise solutions to the OpenVMS marketplace for more than 20 years, first with DIGITAL, Compaq, and now HP. After the merger with Compaq in May 2002, HP announced that they will sustain the existing OpenVMS roadmap. The OpenVMS port remains one of Oracle's top platforms, with a large and loyal customer base. Oracle is committed to providing continued ports of its core database to OpenVMS, working with HP on its latest roadmap."

Refer to the website at: (http://h71000.www7.hp.com/solutions/oracle/openvms_sod-10-02.html

In July 2003, Oracle provided Newfoundland Power a personalized letter outlining their commitment to OpenVMS and their roadmap for future enhancements and support. In this letter they have stated they intend to support their Oracle Relational Database Management System product on the OpenVMS platform until at least 2009. A copy of their letter is is provided in Appendix L – Oracle Commitment Information

Cognos Commitment

The CSS online functionality is almost completely written in the Cognos Axiant toolset and significant portions of batch and report processing are written in the Cognos Powerhouse toolset. From a global perspective these tool sets are not common, having a very low percentage of market penetration. Cognos has only identified three ISVs that market business software packages written in the Powerhouse toolset. From this perspective they are niche tool sets.

Cognos Powerhouse and Axiant can be run on the OpenVMS, Unix and Windows operating systems. Cognos has approximately 2900 supported PowerHouse, PowerHouse Web and Axiant customers worldwide. Of these 2900 customers, more customers are running these tools with the OpenVMS platform than other platforms.

Cognos is now primarily a business intelligence technology company whose primary product lines are centered around reporting software offerings and not application development software as it was in the 1980’s. The low visibiltiy of the application development products is evident by their lack of presence on their corporate web site.

Cognos has indicated though conference calls that they plan to continue to plan and execute product release strategies as long as there is customer demand and business viability. They currently do not have any end of life timelines for the OpenVMS platform.

Cognos’s product plan is to put out a new base release about once a year or year and a half, with maintenance releases in between. The focus of these releases will be customer driven enhancements and database and operating system conformance.

Cognos recently provided Newfoundland Power with a written commitment to the future support of Powerhouse and Axiant on the OpenVMS operating system. This is provided in Appendix M – Cognos Commitment Information.

Cognos continues to have a number of business partners who maintain and deliver Powerhouse and Axiant based solutions. In Canada, there is a concentrated presence of Powerhouse and Axiant users in the Ottawa area.

1.3. Summary Analysis

Based on all of the research and vendor support plans identified above, two major conclusions can be made:

1. There is no immediate urgency to get off the OpenVMS platform. The CSS is a custom developed solution and therefore not dependent on Independent Software Vendors of business applications. HP has a solid long-term OpenVMS support and upgrade roadmap and both Oracle and Cognos are committed to support OpenVMS for their toolsets according to HPs roadmap.

2. However, sales of OpenVMS based systems are shrinking and the long-term viability of the platform is questionable. Newfoundland Power should continue to reduce dependence on the OpenVMS platform and the Cognos Powerhouse and Axiant application development toolsets wherever possible. Reduced dependence will minimize the effort required if and when a technical migration to another platform is required. It will provide the flexibility to support new functionality and utilize more cost effective technologies not available on the OpenVMS operating system. This strategy will leverage new skill sets and new technologies while protecting the heavy investment in business processes already programmed to run on OpenVMS.

2. Package Purchase and Implementation

2.1. Description of Alternative

This alternative involves purchasing and implementing a software package that will replace the existing CSS functionality. This very large project would involve implementing completely new business processes, technology processes and supporting hardware infrastructure.

By purchasing a new CIS software package Newfoundland Power would eliminate reliance on aging technology (the OpenVMS operating system in particular) and could possibly receive additional capabilities and realize efficiencies not possible in the current CSS.

An example of potentially increased capability and efficiency is that typically CIS software packages are highly configurable where programs such an Equal Payment Plan have many flexible options for delivery of the program that can be changed directly by the customer service department, and are not "hard coded" into the software. For example, by adding customer service options (e.g. allow an 11 month payment plan or 9 month payment plan) without relying on expensive technology resources customer service could be improved and efficiencies obtained.

However a comprehensive view must be taken to assess such things as need, costs and project risk to determine whether a package purchase is justifiable.

2.2. Summary of Research

<u>Industry Experts and Reports</u>

As a result of attendance at a Customer Information System Conference in 2002, we received an early understanding that replacement of our current CSS could be expected to cost more than $10 million.

In January and in March two conference calls were conducted with META Group's Energy Industry expert Dr. Zarko Sumic. META Group is a leading provider of information technology research, advisory services, and strategic consulting. An overview of META Group and Dr. Sumic's resume are provided in Appendix N - META Group Information. The topics of these calls were regarding the state of the market with respect to CIS packages and what utilities are generally doing within the market. The following is a summary of the information learned via these conference calls:

- Demand for CIS packages is currently extremely low and vendors are giving deep discounts particularly on license fees.

- The analyst was not aware of any other utility operating a CIS on the OpenVMS platform.
- Very hard to justify new CIS based on pure “Return on Investment”. Total project costs for a package implementation ranges from $35 to $65US per customer.
- Technology obsolescence is rarely the only driver of a CIS replacement. There is almost always a business reason to replace.
- Total project costs should take into account system integration services, gap analysis, customization requirements, data migration, hardware purchase, infrastructure tuning and so forth. When getting low project quotes look closely to ensure these have been considered.
- Generally with the lower cost packages you can negotiate a better deal on license fees but functionality will be less complete.
- Bill printing tends to be an external or add-on function.
- Credit and Collection is a functional area that typically requires customization for utility specific features.

In a META Group Energy Information Services paper released in September 2002 entitled “Viewing the CIS Solution Market: 2002 Edition”, several relevant points were also made, including: energy utilities are focusing on “more tangible bottom line (cost reduction) impact by improving operational efficiency and customer service efficacy” when looking at package solutions and with the “still high CIS replacement cost (even with deep license discounting) energy executives are seeking hard monetary business case benefits”. One example is “they are proceeding only where the current system’s cost of ownership is prohibitive”. A copy of this article is included in Appendix O – Meta Group Viewing the CIS Market 2002 Edition

<u>Request for Information from CIS Vendors</u>

To gather more information, a Request for Information (RFI) was prepared and sent to major industry vendors of CIS systems and selected other vendors who may have acceptable solutions.

META Group periodically analyzes the CIS product market and publishes a market summary report identifying industry leaders and challengers in the utility CIS market. In a market summary published in early 2002 META Group identified no market “leaders” and eight “challengers” in the market. Of these eight, one is no longer in the North American market place at the time of this writing. The fact there are no leaders, along with major players dropping out of the market, indicates there is consolidation and volatility in the market.

The RFI was sent to the six of these “challenger” vendors with whom contact was able to be made. Of these six, four responded to the RFI. The RFI was also sent to and responses were received from five other CIS vendors with a smaller market presence.

Three of the four vendors (Open-C Solutions, SAP/Deloitte Consulting and SPL/Bearing Point) provided estimated licensing and implementation services costs in excess of $9 million. The average software licensing and services costs quoted from all vendors who responded was $6.7 million.

These costs only refer to package purchase and implementation costs paid out to the vendor and other third parties. Internal labour costs to select the software, configure it, implement the software and new business processes and perform training etc. are not included and must be estimated to obtain a full picture. As well individual responses may not include other significant costs, such as hardware infrastructure costs or travel and living costs for the vendor.

Finally all vendors assumed no customization of their package will be required. Customization is a major contributor to higher cost of package implementation. For the less expensive solutions META Group has indicated during conference calls that there is likely less capability of the package to cover all business requirements and therefore it is more likely that customization will be needed.

Based on these responses and taking into consideration all project costs it is reasonable to estimate that a full package implementation will cost in excess of $10 million.

Energy Planning Network CIS/CRM Utility Consortium

The Energy Planning Network (EPN) is an unaffiliated research and networking company that supports sharing of information among utilities regarding Customer Information (CIS) and Customer Relationship Management (CRM) systems. Software vendors cannot become members and there is no affiliation with consulting companies or any other vendor. The benefit of this type of consortium is that member utilities are able to obtain information about each other’s experiences surrounding CIS/CRM systems that they would not share publicly. Given the competitive nature of the North American Utility market, this is an excellent source of information for utilities trying to make decisions on multi-million dollar CIS/CRM projects.

Newfoundland Power became a member of this consortium in May 2003. The EPN was asked to perform a survey of electric utilities with a similar number of customers who have recently implemented a CIS package. These utilities were asked about the costs associated with these projects.

Six utilities responded to the survey. Customers served ranged from 100,000 to over 350,000 with an average of 231,000. Four of the utilities distribute only electricity, one bills for a combination of electric/gas/water/sewer/solid waste/stormwater and one is a water/sewer/stormwater utility.

Of the six utilities one reported a total project cost of over $35 million; one reported a total package cost of over $15 million; one small municipal utility reported a total project cost of over $5 million; one utility reportedly spent over $5 million on just package purchase and services; and another is reportedly spending $3 million for just package purchase and services. These last two were fix priced contracts - with numbers being provided through 'off the record' sources.

The EPN's biggest success factor in being able to provide service to members is strict confidentiality. As a result, EPN has, as a condition of providing the survey results to the Company, not allowed the sharing of the details of the survey results with any other parties.

2.3. Summary Analysis

Several factors were considered when assessing whether the Company should purchase and implement a software package. The primary factor is need; however, cost and risk are major considerations as well.

Need:

Based on the Functional Assessment and Customer Service Vision outlined earlier, the current and near term need for a completely new set of business processes for Customer Service is not a major requirement.

While there are a significant number of identified potential enhancements, few of these changes are related to complete lack of functionality provided by the system. In most cases these requests are for modification of existing functionality to provide improved service offerings or to make existing processes more efficient.

From the Customer Service Vision perspective, the expected future enhancements and new business processes to be implemented in the majority of cases center around functionalities which interface with the "core" CSS. Examples of this are increased investment in off-site meter reading features, new ways of accepting cash, new bill design and presentment methods and expanding customer self-service options via the internet. Also information access (which is not a core CSS functional issue either) is a key theme, particularly in the Collections processes. All of this indicates that the Company does not appear to need a completely new "customer system engine" at this time to support the Customer Service activities, but rather "add-on" capabilities and tweaking of existing capabilities.

Cost:

Based on surveys, vendor RFI responses and industry expert advice, it is reasonable to assume that a replacement of the CSS via a package implementation would cost in excess of $10 million.

Risk:

The major risks associated with full-scale package implementation are primarily centered around project risk. Package implementations for CIS systems are extremely large projects and total project failure (the project is stopped after significant investment has been made with nothing implemented) has been commonly reported in the industry over the years. For projects which do come to completion, major cost overruns and schedule overruns are common as well. Two of the higher cost implementations at utilities surveyed by the Energy Planning Network had cost overruns in excess of 25%. As noted in the very recently released Warren B. Causey 2003 CIS/CRM report: “Utilities …. have become highly risk averse and view large-scale CIS implementations as overly expensive and risky”. As a result, project risk and cost are major deterrents to a package implementation.

In summary, there is a lack of functional need for replacement, extensive risk associated with a package implementation, and a project cost of at least $10 million is to be expected. If package replacement becomes a desirable option, then an extensive and rigorous scoping and selection project will be required to truly ascertain total project costs and minimize risks.

3. Outsourcing

3.1. Description of Alternatives

Alternative outsourcing models applicable to utility Customer Information Systems are usually variations and combinations of the Application Service Provider (ASP) model and the Business Process Outsourcing (BPO) model.

In an ASP model “application hosting” is quite common. In this scenario rather than purchase a software package and implement it in-house, the Company does not actually purchase anything but pays a vendor to allow the Company to perform its CIS functions on their software. They own the software and the Company pays an annual or monthly fee to “rent” their software. There are a number of variations on this scenario, such as running the software in-house or running it at the vendor’s site via the web.

In the BPO model, not only does the Company “rent software”, but the outsourcer also performs the business function as well. A very common example is an outsourced call centre. The people actually answering the phones, responding to customer inquiries and orders would not be Newfoundland Power employees. Rather, all of these business processes would be performed by the outsourcer. Typical BPO targets include customer contact center operations, IT data centre operations, application support, cash processing, billing, bill print, bill mailing and collections.

3.2. Summary Analysis

For purposes of this analysis, only full scale ASP or BPO alternatives were considered which would involve the elimination of the core of the existing in-house CSS.

According to information received from IT industry advisors such as META Group and Gartner, many organizations tend to take advantage of alternative outsourcing models because:

- They do not already have the capacity in-house. Large mission critical applications such as a CIS (regardless of size of organization) require extensive "care and feeding" to properly run. This would include support staff to respond to functional problems or usability questions, administrative staff to adjust parameters for operating requirements and technical staff to troubleshoot technical issues or extend system capabilities etc.
- They do not already have the skill sets in house to run the system. Intertwined with the capacity issue is the presence of in-house expertise/competence. Such applications may require unique technical infrastructure not already utilized in the organization and, therefore, the organization implementing it would need to maintain new expertise (e.g. Oracle DBA).
- They are willing to adjust business processes to the boundaries of the package/services, are not unique or don't need to be unique and therefore do not require customization of a solution.

According to META Group, processes that are candidates for outsourcing are those in which the process is not unique (no special requirements or rules) and the organization are not very good at executing today. Given the high level of customer service as evidenced through satisfaction surveys and some of the more unique aspects of the Newfoundland environment (e.g. culture, customer diversity) a full outsourcing of the Customer Service business function is not a practical option.

ASP and BPO model for portions of the Customer Service function should continue to be considered where there is both opportunity and merit.

4. Technical Migration

All technical migration alternatives involve some replacement of technology components without significant change to functionality. The purpose of a technical migration is to retire obsolete technology (costly to maintain or risk of failure) and to take advantage of advancements in technology while keeping the system functionality largely intact.

4.1. Description of Alternative

In the case of the CSS a technical migration is considered a viable option for preserving the business logic already embodied in the current CSS while reducing reliance on the OpenVMS platform and related technologies.

Two basic alternatives for technical migrations were explored:

1. OpenVMS re-platform including redeveloping the major application development technology components according to the Company's Target Technology Architecture (eliminate reliance on Cognos Axiant and Powerhouse proprietary software).

2. OpenVMS re-platform while keeping major technology components (e.g. Powerhouse, Axiant etc.). This is more of an interim step, as the niche development tools would not be migrated.

4.2. Technical Migration Assessments

To help identify viable alternatives and to provide budget level cost estimates of each alternative a number of organizations were engaged to provide assessments of what would be involved for different technical migration scenarios.

Our major technology suppliers, HP and Microsoft were requested to provide assistance in determining feasible alternatives and assessing costs and fit to our technology direction.

According to Gartner, the leading technical migration vendor who has extensive experience with OpenVMS applications is a company called Sector7. Newfoundland Power contracted with Sector7 to provide a recommendation of the most appropriate technical migration alternative and to provide costs for that alternative.

Core, the only software company in the world offering automated migration of Cognos Powerhouse/Axiant code to Microsoft .Net was asked to submit an estimate to convert the code for the CSS.

Finally, although their assessments are not provided, two other companies, Intertech and InBusiness, were contacted to provide information about the feasibility and costs to migrate the Cognos Powerhouse toolset unchanged to the Windows or Unix environment. The Company views this as an interim step in a phased in approach to move the CSS to an acceptable technology environment. These vendors indicated that this small portion of an interim technical migration is both feasible and not a major cost issue.

Microsoft Assessment

As a key partner, Microsoft was invited to review our situation and both assist us to identify viable technical migration alternatives and identify how Microsoft services and tools could be leveraged. A three day on-site brainstorming session was conducted with the project team by a Microsoft Solutions consultant. Prior to the session our internal system functional and technical documentation and technical current assessments and target architectures were provided to the consultant. Microsoft responded with a 32 page report outlining feasible target architecture alternatives, including the pros and cons of each option. A copy of the report is found in Appendix P - Microsoft Newfoundland Power CCS Migration Analysis.

The following summary results were obtained:

- The report recommended a technical migration of the CSS to the Windows environment and a SQLServer database. This was recommended as a result of ongoing DBMS licensing being cheaper and with SQLServer there would be less expensive hardware required than for a Unix solution. It was recognized that DBMS conversion from Oracle to SQLServer would raise project complexity, risk and effort. (It should be noted that since this assessment was received, the Company has successfully renegotiated a much cheaper DBMS ongoing licensing arrangement with Oracle)

- The report identified a second feasible option of a technical migration of the CSS to the Windows environment and an Oracle database.

- The report identified a third feasible option of a technical migration of the CSS to a Unix environment and an Oracle database.

- Batch Job Scheduling and Monitoring is not a strength of the Windows environment. The report identified Windows based Batch Job Scheduling and Monitoring tools that should be investigated if the recommended technical migration were to proceed.

HP Assessment (2nd Assessment – Technical Migration only)

HP is a key supplier of technology infrastructure at Newfoundland Power. The current servers and OpenVMS operating system used by the CSS were supplied by HP. As well, all the current Windows servers (hardware), supporting all Company applications, were supplied by HP.

HP was specifically asked to provide an assessment of an appropriate target operating system platform and technical migration approach. HP was provided a copy of all CSS source code, copies of system description, CSS technology assessment and CSS target architecture to assist in their analysis. In response HP provided a 24 page report with recommendations regarding these topics. A copy of the report is provided in Appendix Q - HP Technical Migration Assessment Report.

The following summary results were obtained:

- The report recommended a phased in migration approach where Powerhouse/Axiant toolsets would be migrated intact (no conversion) to the target operating system platform. The reason for this recommendation is to reduce major project risk associated with a full-scale migration. HP estimated that migration services costs to complete for this option to be approximately $800,000. These costs do not include all project costs such as internal labour, software licensing, hardware and such things as user training and other implementation costs. Redevelopment of the major technology components would be completed as a next phase at some later date. No costs were provided.

- HP estimated that service costs for a full scale technical migration (either to Windows or Unix environment, but keeping Oracle database) would be about $2.5 million. These costs do not include all project costs such as internal labour, software licensing, hardware and such things as user training and other implementation costs.

- It was recommended that if a full scale migration to the Windows environment is preferred, the Company should wait until the .NET development environment matures and Microsoft supports 64 bit hardware. This would be about a two year timeframe.

- It was recommended that, if full scale migration to HP Unix environment is contemplated, to wait until 2005 when certain critical feature improvements to that operating system platform will become available.

Sector7 Assessment

Sector7 was contracted to identify an appropriate target operating system platform and recommend a technical migration approach. Sector7 was provided a copy of all CSS source code, copies of system description, CSS technology assessment and CSS target architecture to assist in their analysis. Sector7 responded with a 35 page report providing recommendations on this mandate. A copy of this report is provided in Appendix R - Sector7 Technical Migration Assessment.

The following summary results were obtained:

- Sector7 recommended a phased in approach whereby the CSS application would be migrated to the Unix Operating System platform with the Powerhouse/Axiant software migrated intact (no conversion). Sector7 estimated the cost of their services for this option to be about $920,000. These costs do not include all project costs such as internal labour, software licensing, hardware and such things as user training and other implementation costs.

- Sector7 feels a full scale migration will be an extremely large effort with high risk of failure. Therefore they recommended that redevelopment of the Powerhouse/Axiant software to a new development language such as Microsoft .NET would be a second phase to be completed some time after the recommended initial migration. No costs were provided for this second phase.

- Sector7 recommended use of Sector7 proprietary tools for emulation of OpenVMS DCL and batch process scheduling on the Unix platform for the initial migration.

- Sector7 provided a number of suggestions for replacing technology components and extending the CSS technical environment once it has been migrated to the Unix platform.

- Sector7 does not recommend migration of the Oracle DBMS to Microsoft SqlServer DBMS. Sector7 feels this would be a major re-engineering project.

CORE Migration

CORE is the only Company in the world that utilizes automated tools to convert Powerhouse/Axiant code to the Microsoft .Net environment. Core was specifically asked to provide a cost estimate to convert the online Axiant functionality and various Powerhouse batch processing procedures to the .Net environment. Core was provided a copy of all the CSS source code.

Core estimated a 12 month fixed price, $2.1 million project to convert all Powerhouse/Axiant software to the Microsoft .Net environment and deliver as unit tested and functionally tested software. This estimate does not include migration of COBOL, DCL or any other non-Powerhouse code. In addition, these costs do not include other project costs such as internal labour, software licensing, hardware and such things as user training and other implementation costs.

4.3. Newfoundland Power Detailed Analysis

Newfoundland Power has some experience with technical migrations as a result of the Technical Migration project completed in 1998. As previously noted, this $2 million project involved converting the database management system used by the CSS from “Rdb” to “Oracle” and converting the online transaction software to a new development language. As a result, the whole online portion of the CSS was re-written and minor changes to every batch processing module was completed. In contrast, a full scale technical migration of the CSS involves not only a re-write of the whole on-line system but extensive re-designing and re-writing of the batch processing procedures (currently well over 1 million lines of code) to retro-fit them to the new platform as well. It is the opinion of the project team that the effort and costs required to perform such a full scale migration would likely be in the two to three times range of the cost of the 1998 Technical Migration project.

Based on all the assessments provided and past experience, a detailed technical migration assessment was completed by the project team outlining the feasible options along with strengths and weaknesses, estimated total project cost and project duration of each option. This more detailed analysis is provided in Appendix S - CSS Technical Migration Alternatives.

The project team considers the most appropriate target environment for the CSS, which optimizes the utilization of operating systems, hardware infrastructure and market leading technology components to be the Windows operating system, utilizing Microsoft technology components on an Oracle database management system.

It is expected that a single project to migrate the CSS to this environment would cost about $6 million dollars and would be 18 to 24 months in duration.

However, the recommendation from this analysis, as supported by HP’s and Sector7’s recommendations in their assessments, is a multi-phase migration to achieve this target environment.

4.4. Summary Analysis

As previously noted, both HP and Sector7 recommended a phased in migration approach to reduce project effort, complexity and therefore risk of failure. As well HP recommended to wait to migrate to either the Windows environment or the Unix environment to take advantage of maturation of technology that would better support the CSS.

Therefore, if a technical migration is the preferred option, the recommended approach is to utilize a multiple project approach to migrate the CSS off OpenVMS and to a long-term sustainable technology environment.

The "Phase 1" project would involve migrating the CSS to the Unix operating system while retaining the Powerhouse/Axiant technology components.

The "Phase 2" project would involve redeveloping the online Powerhouse/Axiant technology components to a Microsoft technology environment while retaining the batch processing procedures in the Unix environment.

The "Phase 3" project would involve migrating the batch processing procedures from the Unix environment to the Microsoft technology environment.

The individual projects range in cost and duration, however collectively they would exceed $6 million in cost and would take 30 to 42 months to complete.

“Bolt On” Applications

“Bolt-on” applications are less of a replacement alternative in themselves as they allow for utilization of new technologies while fulfilling a functional requirement. Implementation of separate modules to extend the capabilities of the existing CSS may be used in conjunction with any of the alternatives being analyzed as a means of efficiently supporting the business function with the most appropriate technology. An example of “bolt-on” functionality commonly implemented with both packages and custom in-house software is bill design and printing software.

A Request for Information was issued to identify applications that may be interfaced with, or “bolted on”, to the current CSS. Once compiled, this inventory of bolt-on applications will be evaluated when considering alternatives to future reprogramming of a particular component or functional area of the CSS.

The list of vendors was prepared from a number of sources, including the Skipping Stone Fall 2002 CIS/CRM Software Report, exhibitors from the 2002 CIS Conference, TMG Presentation to Newfoundland Power in the fall of 2002 as well as others. (See Appendix T – Summary of Bolt-on Vendor Responses) The RFI was distributed to 54 CIS and related vendors.

The response rate was disappointing with only 15 vendors provding a response.

Several package vendors responded with information on their full system; however, on closer inspection it is doubtful their systems could be implemented in a modular fashion.

Because the vendor information was general and high level, evaluating the product for fit and functionality was not possible. However, it did give the Company an understanding of what was available the marketplace and may enable the Company to identify alternatives to reworking the CSS. No vendor was identified as providing an outstanding solution for a particular area.

Vendors responded with standalone bolt-on modules in the following functional areas:

- Field Services
- Bill Print
- Industrial Billing
- Load Management
- CRM features

Recommendation

1. Scenario Analysis

The Company has no current functional requirement that would require a wholesale replacement of Customer Service business processes either through package purchase or outsourcing. Although there are a significant number of functional improvements to be completed, the current CSS is adequately supporting the business and it is expected to continue to do so over the next few years.

If a package were purchased, the total project cost would be in excess of $10 million. Project duration would expected to be in the range of 18 to 24 months and there will be a significant period during the project when all but absolutely urgent software change will be suspended. A key benefit is that many of the outstanding functional enhancements for the existing system would be delivered as features of the package. However, for large package implementations the impact on the organization and project risk tend to be very high as a result of both a change-out of technology and business processes at the same time. It is questionable whether the need for a functional replacement is sufficient to deal with these issues at this point in time.

The recommended phased-in technical migration, in total, would exceed the $6 million estimated cost of a “big bang” full-scale technical migration. Unlike a package implementation, the resulting system will not have any major feature enhancements added, as the least risky approach to executing a technical migration is to leave all business processes intact. As well there will be a significant period during each project when all but absolutely urgent software change will be suspended. Overall the business would be severely restricted in the ability to react to a change in the business environment or to even implement a major functional upgrade over the as much as 42 month period it could take to complete all phases of the migration.

An analysis of the current situation shows it is clear that although the Company should continue to reduce dependence on the OpenVMS platform, there continues to be time to get the CSS off the platform in an orderly and cost effective fashion. Support for the OpenVMS environment will continue to be at acceptable levels to run this mission critical application for the next two to five years and possibly longer. However the evolution of HP’s roadmap and overall industry support for the environment needs to be continuously monitored.

2. Recommendation

2.1. Description of Recommended Scenario

The recommended scenario is to continue to run the CSS on the OpenVMS platform while making evolutionary changes to reduce dependence on the OpenVMS platform.

Where possible, any additional functionality will be modularized and developed according to the Microsoft technology environment. Utilizing “bolt on” applications to meet functional needs will be a standard alternative to be evaluated, where practical. Significant changes to existing modules will be evaluated and re-written in platform independent technology if practicable.

Significant changes in business direction or change in commitment to the OpenVMS platform will be monitored annually and the timing of replacement identified accordingly. A reassessment similar to this analysis will be completed in 2006. The timing of this reassessment makes sense as some of the major milestones in HP’s OpenVMS roadmap will have been reached and the CIS Package vendor environment may have stabilized.

Each year, until the ultimate timing of replacement is identified, there will be specific projects identified which will both give business value and will actively reduce dependence on the OpenVMS environment.

2.2. Evolutionary Changes

The following types of evolutionary changes will reduce dependence on the OpenVMS platform and/or address several of the weaknesses identified in the Technology Assessment:

- Write new functionality as “stored procedures” rather than Cobol or Powerhouse. Rewrite existing modules as “stored procedures” where practicable.
- Utilize existing standard reporting and business intelligence toolsets (Impromptu, Powerplay) in the CSS environment, thus eliminating reports written in Powerhouse and DCL
- Develop a reporting environment that is friendly to user reporting tools (Impromptu), thus eliminating existing production and ad-hoc reports.
- Purchase and implement “bolt-on” software for functional enhancements rather than custom development in-house.
- Leverage existing in-house technology to extend the CSS. Examples include existing printing facilties, Itron Meter Reading System, Aspect Customer Contact Center technology and the current Internet and Intranet.
- Increase integration with Microsoft Office products.

- Develop new integration in the new, adopted technologies rather in traditional CSS code.

2.3. Cost Analysis

The project team conducted an analysis of the project/implementation costs and the annual costs associated with a package purchase scenario, technical migration scenario and remaining on the OpenVMS platform.

This analysis concluded that although the annual costs to maintain and operate the systems are comparable, the very high projects costs associated with a package purchase and with a technical migration makes staying on OpenVMS the clear choice from a cost perspective.

Following is a comparison table of the project and ongoing costs associated with the major alternatives. As well, explanations of the various cost items and a more detailed analysis is provided below.

Alternative Cost Comparison Table

	Stay on OpenVMS	**Package**	**Technical Migration**
Total Project Costs	**$996,000**	**$10,000,000**	**$6,000,000**
Annual Enhancements/Upgrades			
Infrastructure	100,000	50,000	50,000
Application	340,000	200,000	340,000
Annual Support Costs			
Hardware Maintenance	150,000	150,000	150,000
Software Maintenance	132,000	400,000	75,000
IT Support Labour	424,000	250,000	375,000
Cust. Service Support Labour	105,000	175,000	105,000
Total Annual Costs	**1,251,000**	**1,225,000**	**1,095,000**

The following are explanations of the costs provided:

<u>Total Project Costs:</u>

For the “Stay on OpenVMS” option all projects from 2004 to 2008 which will reduce dependence on the OpenVMS platform are provided. These projects will also provide functional improvements.

A baseline of $10 million for a package purchase and implementation is used, however total costs could be much higher. This project would deliver functional improvements.

To simplify comparison, the costs of a full technical migration, rather than a phased in technical migration (where the project costs would be higher) is assumed. No major functional improvements would be delivered.

<u>Total Annual Costs</u>

Annual Enhancements/Upgrades – Infrastructure: These are capital items which would enhance the Infrastructure environment related to the CSS. It is expected that for the Stay on OpenVMS scenario, more hardware purchases would be required to keep the CSS infrastructure viable, whereas for the Package and Technical Migration scenarios, major upgrades would be included as part of the original projects.

Annual Enhancements/Upgrades - Application: This includes major package software upgrades and enhancement projects for the CSS. For the Stay on OpenVMS scenario, functional improvements will proceed but will be less than for the Technical Migration scenario as justification will require a short payback period and the majority of enhancements also reduce dependence on OpenVMS platform which are included in the Replacement Project above. For the Package scenario, there would expect to be limited functional improvements required however a major product version upgrade will be required every two to three years.

Annual Support Costs – Hardware Maintenance: This includes maintenance agreements required to maintain all hardware infrastructure related to the CSS.

Annual Support Costs – Software Maintenance: This includes Database Management System (DBMS), bolt-on software and package software annual maintenance agreements. The Package scenario would be much higher than the other two as a result of the package maintenance agreement which typically is 20 to 25% of original package cost. The Technical Migration scenario is expected to be cheapest as a result of the reduced annual maintenance costs required to support the Microsoft tools used by the CSS (already covered by current Microsoft Enterprise Agreement)

IT Support Labour: This involves Information Services Department (IS) labour to deal with problems with the application and perform maintenance. Given the “hard coded” nature of the existing CSS, the IT labour to support the application is much higher than for the Package scenario. Technical Migration would be somewhat less than for Stay on OpenVMS as some benefits will be derived from utilizing the new software tools.

Cust. Serv Support Labour: This involves Customer Service Department labour to deal with problems with the application and perform maintenance. In the Package scenario, as a result of a Package being highly configurable, the Customer Service support labour will rise as a result of being able to support the application without IS involvement.

Analysis

It is expected that post-implementation support costs in the first two years after large Package and Technical Migration projects are completed would be higher than normal. This was not included when developing annualized support costs for these two scenarios.

Overall, annual costs for all three scenarios are not too far apart. A more detailed analysis indicates each scenario has it's pros and cons. So for example, for a Package scenario, less functional enhancements are expected and therefore lower costs in that category, however Vendor support costs are much higher than if the Company supported the application internally. Regardless, this reflects that significant resources are required for this large and complex application.

The high initial project costs associated with the Technical Migration and Package scenarios relative to the comparable annual costs associated with the Stay on OpenVMS scenario indicates that neither a replacement nor a migration are justified at this time.

2.4. Risk Mitigation Strategies

In the course of reviewing the OpenVMS issue a number of concerns were raised which will need to be addressed as long as the OpenVMS environment is maintained. The following are the risk mitigation techniques planned for a number of these areas of concern.

Retention and Scarcity of OpenVMS Skills Sets

Currently there are three employees within the Company who have OpenVMS experience (two with current up-to-date knowledge). OpenVMS knowledge will continue to be fostered in these two employees. If these resources become lost to the Company in the next three to five years, we will work with HP on developing an arrangement whereby HP provides day to day support. This would be costly if required, but an acceptable risk in the short-term.

Retention and Scarcity of Powerhouse/Axiant Skill Sets

There are several employees who have extensive experience in the Powerhouse/Axiant tool sets. Although we prefer otherwise, at least one employee will work regularly on initiatives which will allow them to retain their expertise. As well, Xwave, the local consulting company, has several employees with extensive Powerhouse/Axiant experience. Finally, companies such as InBusiness and Intertech can be retained to perform Powerhouse/Axiant enhancements and changes.

OpenVMS and Powerhouse Available Training

Current expertise is such that no additional training is required in the future. If new employees require specific training then, as has been done in the past, an appropriate training course will be brought in from the mainland or the employee will be sent wherever it is offered in North America.

As well, the strategy of gradually rewriting components of the system will reduce dependence on the OpenVMS platform such that employees with the newer skill sets can perform maintenance and enhancements.

Maintaining Hardware Infrastructure

As previously noted, although HP will be continuing to sell Alpha Server technology until at least 2006 the specific Alpha Server model currently in use at Newfoundland Power is no longer being sold by HP.

HP has provided assurances that in the short-term, as a result of widespread use of this model, they have a healthy supply of spare parts available. As well, as contingency, the Company will conduct a search for critical spare parts and set up a small inventory of these parts in case they cannot be obtained from HP in a timely manner. As well, availability of spare parts will be rigorously monitored and if required newer model Alpha Server technology will be purchased.

Finally the Itanium hardware platform is planned to be available for OpenVMS in 2005. If cost justified and necessary as a result of reduced reliability of the Alpha Server platform, purchase of the Itanium hardware technology may be made.

2.5. Functional Enhancement Strategy (1 – 5 Years)

The following is the functional enhancement strategy in light of continuing to maintain CSS on the OpenVMS platform.

Since a complete replacement of the CSS is not planned within the next one to five years, some components of the system will require a significant upgrade or replacement within that time period. In addition, during this period, the Company may pursue new programs and technologies to advance customer service and reduce ongoing costs. Such upgrades must be justified within a short payback period, considering the potential for a CSS replacement as early as 2008 (assuming the 2006 study recommends replacement and the project begins immediately).

It is expected that to meet the needs of its customers and to realize efficiency opportunities, Customer Service will require at least one major upgrade or replacement project per year, in addition to other “smaller CSS changes”. A major replacement/upgrade project requires significant IS resources, in the range of 1 to 2 or more Full Time Equivalents (FTEs). Corresponding Customer Service resources also are assigned; these usually range from one-third to one-half the assigned IS resources.

Changes due to compliance with external agencies, such as the PUB or the federal government, are not included as part of an enhancement project. This could include requests such as seasonal rates or a change in the application of the HST. These changes are dealt with as they arise; however, they can displace other work, including projects and small upgrades. Resources and time required to resolve a compliance issue may need to be transferred from other CSS changes.

As an aid to determine if an enhancement to a specific area of the CSS is required, one or more of the following characteristics should be present:

- a particular CSS component is causing significant problems or errors such as incorrect information or billings.
- the problem affects the general population of customers as a whole.
- significant manual intervention is required to administer the program correctly and/or keep it on track.
- the CSS component is limited in its ability to respond to specific requests on a timely basis.
- the CSS component does not meet the Company’s business objectives.
- Expected benefits outweigh costs assuming a relatively short payback period.

During any given time period, there are competing projects for the same resources. Meeting regulatory requirements and reducing operating costs are the primary drivers when setting priorities.

The CSS Functional Assessment identified a number of small effort, high priority items. These should be implemented as soon as possible in 2003 or 2004 as part of the Small Upgrades.

In addition, the CSS Functional Assessment identified a number of high priority opportunities of significant effort that fit the above criteria. Due to this large number of high priority projects, at least one large project opportunity should be addressed on an annual basis as the “main” project for the year. However, there needs to be other smaller changes made as well.

The high priorities list should be maintained and reviewed each year according to the above criteria and one opportunity selected as the “main” project for the year.

Bug fixes and small changes (eg. edits) will continue as usual.

2.6. Implementation Plan

The following are replacement related enhancements planned in 2004 and expected to be scheduled from 2005 to 2008.

In 2004:

- Bill Print – utilize existing printer capabilities, retire bill print software
- Form Letter Print – utilize existing printer capabilities; retire WordPerfect on OpenVMS and extensive DCL procedures.
- Reporting – Adopt standardized reporting tools and retire a number of existing production and ad-hoc reports.

2005 – 2008:

- Implement cross platform batch processing procedures; retire significant amounts of DCL
- Implement a more sophisticated reporting environment with Data Warehouse features; retire numerous reports.
- Implement new cash register system; retire some OpenVMS cash processing procedures.
- Implement Customer Relationship Management functionality; will eliminate portions of existing online functionality inside CSS (Customer Inquiry screens).
- Reassess the status of CSS and OpenVMS Obsolescence in 2006.

Appendix A - PUB OpenVMS Obsolescence Report Internal

Obsolescence and the OpenVMS Operating System
An Emerging Technology Issue at Newfoundland Power

August 2001

Table of Contents

Introduction

Information technology is a necessary and vital component of the resources required to provide low cost, efficient and reliable customer service. The need to replace and modernize information technology infrastructure is fundamentally the same as the ongoing requirement to replace and modernize any other component of the Newfoundland Power's (the Company) electrical system infrastructure as it deteriorates or becomes obsolete. One of the major components of the Company's information technology infrastructure is the OpenVMS operating system.

In recent years there has been a gradual trend away from the OpenVMS operating system in the information technology industry. The increasing popularity of operating systems such as Microsoft Windows and Unix, as well as the rapid developments in Internet technologies, have been key factors in this trend.

Many of Newfoundland Power's business applications are installed on OpenVMS. This report examines the issue of declining software vendor support of the OpenVMS operating system, and the implications of its obsolescence within Newfoundland Power.

Background

Newfoundland Power's information technology (IT) investment is comprised of two basic components: 1) applications, and 2) technology infrastructure.

The applications component consists of a range of technology tools that support business processes at the corporate, workgroup and individual employee level. Applications include common business tools such as electronic mail, while others such as the Customer Service System (CSS) provide functionality that is specific to Newfoundland Power.

The technology infrastructure consists of a variety of components including personal computers (PCs), larger multi-user computers known as shared servers, peripheral devices such as printers and scanners, and a variety of software tools such as OpenVMS and Windows that allow the various components of the infrastructure to work together to form a network infrastructure.

What is OpenVMS?

OpenVMS is a software tool that is categorized as a server operating system. It is a critical component of Newfoundland Power's current technology infrastructure and its purpose is to:

- control server hardware and manage how this hardware functions;
- enable applications to reside on servers and to utilize capabilities such as processing capacity, memory and storage;
- manage how the server connects to the network infrastructure;
- manage server security and application access by computer users;
- allocate server resources between multiple users and applications; and,
- manage the performance of the server and applications.

The History of OpenVMS

OpenVMS and its predecessor, VMS, have a long history dating back to 1977 when it was first made commercially available by Digital Equipment Corporation (DEC). Through the 1980's, DEC's OpenVMS operating system, along with its mainframe hardware and first-rate support, enabled DEC to compete with the best offerings of other leading vendors such as IBM.

In the mid-1990's, OpenVMS evolved to support the movement from mainframe computing to client-server computing with personal computers playing a larger role in supporting computing requirements. OpenVMS, together with other DEC assets, were sold to Compaq Computer Corporation in 1998.

Since the mid-1990's, Microsoft has emerged as a leader in the operating system software market with its Windows line of products. There has also been a rapid expansion in the development and use of Internet technology. A combination of these and other factors has led to the decline in market acceptance of OpenVMS as a leading operating system platform.

Technology Obsolescence

The rapidly evolving information technology industry produces a continual stream of new products focused on identified or perceived needs. Like many other industries, information technology products generally follow a cycle of market introduction, assessment, acceptance or rejection and ultimate replacement by a new or substantially changed product. The timeframe involved varies greatly by product but is generally based on market interest and momentum.

Technology obsolescence occurs when a product is no longer able to meet market needs. The actual reasons can vary from limited technical capabilities to a lack of alignment with industry standards. Regardless of the cause, the result is the same. Independent software vendors will discontinue further development of the technology on the grounds that there is insufficient market to justify additional investments. As vendors abandon older technologies to pursue new market opportunities, support for the technology will eventually be discontinued.

What are the signs?

Leading IT analysts such as the Gartner Group[1] often provide early warning signs of the potential decline of a technology. Through regularly published articles, seminars, conferences, and client consultations, these groups project the success or failure of specific technology vendors and products.

A key indictor of the position of a technology in the market is the extent to which the technology is considered strategic by major application vendors. The strongest advocates of the decline of OpenVMS indicate that the lack of development of OpenVMS-based products among these vendors is a major concern.

Other indicators include:

- the lack of coverage of the product at conventions, conferences and trade shows;
- training is no longer available;
- consultants with OpenVMS skills are increasingly more difficult to find and the costs are increasing; and,
- colleges and universities have removed the technology from their academic programs.

What are the implications?

The impact of a technology becoming obsolete is complicated by the fact that most IT environments consist of a variety of interrelated software products. This is particularly the case

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand technology and drive business growth. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 80 locations worldwide.

when referring to an operating system since it comprises a significant portion of the platform (the other major component being the shared server) upon which most other products operate.

This interrelationship between software products is critical to ensuring that the software applications they support remains efficient and capable of supporting the specific function of the Company for which the application was developed, such as customer service. If a vendor for one of these software products decides to stop developing newer versions of its product on OpenVMS, the entire application becomes unstable thereby jeopardizing customer service and operating efficiencies.

Newfoundland Power's Assessment of the OpenVMS Situation

When will OpenVMS decline?

To date Newfoundland Power has received two OpenVMS related notifications of discontinued support for a specific software technology. The first was from Andersen Consulting in 1995 relating to their discontinuation of development, and eventually support, for some of the technical components of the CSS. In July 2000, StarGarden, the Company's Human Resources and Payroll software vendor, advised that they were discontinuing support for components of their software that use proprietary data storage on the OpenVMS platform. This notification of discontinued support was a factor in the decision to replace the Human Resources and Payroll software in 2001.

Newfoundland Power has experienced other signs that OpenVMS is in decline. This includes slower response to support calls, waiting longer to have software bugs fixed, and very limited access to experienced OpenVMS staff across Canada. The Company recently had to conduct an exhaustive search to find qualified resources to assist with a very technical OpenVMS problem with an Oracle database software product.

The Gartner Group holds the view that "..*organizations with high third party software dependencies should plan to be off OpenVMS by 2003; organizations with maintainable owned source (in-house developed) should plan to be off OpenVMS by 2005.*" Gartner bases this recommendation on its broad knowledge of the enthusiasm for OpenVMS among its 10,000 clients and the declining investments that vendors are making in OpenVMS-based products.

Gartner Group acknowledges that COMPAQ itself maintains a commitment to OpenVMS and in fact may see the OpenVMS environment survive to support very specific applications such as e-business for an indefinite period of time. However, software industry support for OpenVMS as a general-purpose operating system platform for new application development is in decline.

While the decline of OpenVMS has already begun, its duration is likely to be a long and drawn out process because of the large number of vendor products currently installed. Predicting the timing of the decline is also complicated by the many contributing factors and the volatility of the IT industry.

What are the risks?

Applications written by third party software vendors represent the most significant risk for Newfoundland Power. The Company is highly dependent on the vendors to provide support for these applications and to complete enhancements to ensure that their software continues to work with other dependent technologies. The loss of support from a key vendor would substantially reduce the reliability of these applications and would subsequently affect customer server levels and operating efficiencies.

The implications of changing a well-established operating system like OpenVMS are significant. In addition to the effort required to replace the existing applications, all components of the technology infrastructure must also be addressed. In addition to the potential costs involved, there is also the potential for business interruptions through the transition process.

Newfoundland Power is using research, experience and the advice of industry experts in planning for the risk associated with OpenVMS. There is the possibility that support for OpenVMS could be discontinued on a large scale sooner than expected. This would shorten the period of time available to change out existing applications and build the new infrastructure to house these applications.

Newfoundland Power's Plan for Addressing the OpenVMS Issue

Overall Approach

As part of its 2001 business planning process, the Company began to develop plans for addressing the Company's dependence on OpenVMS. The main strategies the Company will employ in guiding the decommissioning of OpenVMS are:

- allow normal application attrition to be a key determinant in the replacement of most applications;
- complete the work over a five to seven year period to facilitate an orderly decommissioning of the OpenVMS environment and to minimize any potential negative impact on customer service;
- capitalize on opportunities to improve operating efficiencies and customer service while replacing applications;
- maintain normal investment diligence by continuing to apply the principles of the IT strategy the Company has adopted to guide its IT investment decisions; and,
- maximize the life of IT assets to the extent possible.

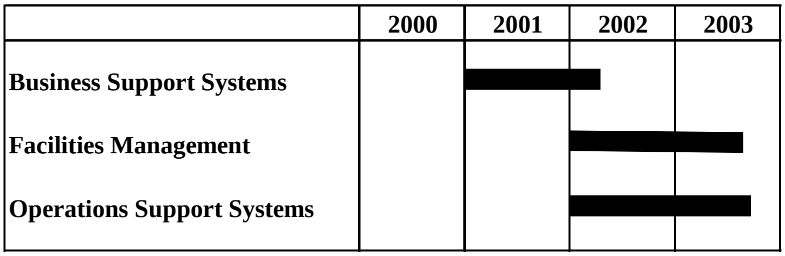
In the next three to five years, many of the Company's existing applications will require a major upgrade or replacement because they lack required functionally to support current or anticipated future business needs. This normal application attrition will resolve much of the OpenVMS issue as major upgrades or replacements will include migrating off of OpenVMS. The Business Support Systems project that began in 2001 is an example of how normal application attrition will contribute to the resolution of the OpenVMS issue.

Replacing critical applications presents an opportunity to improve or enhance the functionality of existing applications. For example, when replacing the materials management system newer electronic commerce capabilities can be added at a reasonable cost as newer solutions are considered. Application change-out decisions will consider opportunities to improve Company operations.

Moving forward, Newfoundland Power will continually monitor developments in the IT industry, particularly as they relate to OpenVMS. It will be important for the Company to maintain sufficient pace to complete the decommissioning of OpenVMS over the planning period and to be well positioned to adjust its overall strategy if the need arises.

Schedule

A high-level schedule for replacing OpenVMS based applications is provided in the following table.



The Company has chosen to focus initially on its Business Support Systems including its Human Resources, Financial, Payroll and Materials Management applications. These applications represent a particularly high risk due to their high level of dependence on OpenVMS, their high level of dependence on third party vendors for support and maintenance, and the limited number of similar installations of the application in other organizations. The Company has included funding to support this phase of the plan in the 2001 and 2002 capital budgets.

In 2002 and 2003, the Company plans to address applications that support the Operations and Engineering areas of the business. These include Facilities Management and Operations Support Systems. In addition to addressing the modest dependence on OpenVMS in this area, the Company expects to realize significant benefits in this area through operating efficiencies facilitated by the improved use of technology. The proposed capital budget for 2002 contains a provision to initiate the Facilities Management and Operations Support Systems aspects of this schedule. Additional funding will be required in 2003 to complete these initiatives.

There are two other OpenVMS systems to be addressed: Outage Management and Customer Systems. Newfoundland Power expects the Outage Management and Customer Systems phases to be the most challenging due to the complex nature of the applications that comprise these portfolios and the importance of these applications in providing high quality customer service. Existing Outage Management and Customer Service applications are highly dependent on OpenVMS but for the most part were developed in-house by Newfoundland Power staff. The risk associated with the dependence on OpenVMS platform for these systems is acceptable for the next three to five years, since Newfoundland Power staff supports these applications.

Experience gained through the previous phases of the OpenVMS initiative will help ensure these applications are addressed in an efficient and effective manner.

Projected Costs

A schedule of estimated budgetary requirements to support the decommissioning of the Company's OpenVMS environment is provided in the following table:

	2001	**2002**	**2003**
Business Support Systems	1,303,000	590,000	-
Facilities Management	-	939,000	270,000
Operations Support Systems	-	1,322,000	636,000

The costs for the replacement of the Outage Management and Customer Systems are difficult to estimate at this time, since the potential vendors for these projects have not yet been evaluated. The anticipated replacement period for these applications is in the three to five year time frame, subject to change based on IT industry developments. This is a manageable level of risk since these applications have been written and supported by Newfoundland Power staff. As well, moving the replacement of these applications out into the three to five year timeframe will allow the Company to maximize the lives of these assets.

Summary

Independent software vendor support for the OpenVMS operating system is in decline. Newfoundland Power has experienced several examples of the impact of this issue, and is responding accordingly. The Company anticipates this issue will continue to emerge in the near term and has initiated plans to mitigate the risks, thereby minimizing any negative impact on customer service and operating efficiencies.

Moving forward, Newfoundland Power will continue to monitor IT industry developments, especially with respect to OpenVMS, and adjust its plans accordingly.

Appendix B - META Group CSS Replacement Study Review

METAgroup

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Mr. Peter Collins
Manager, Information Services
Newfoundland Power

July 1st, 2003

Dear Mr. Collins,

META Group has been retained to offer an expert opinion on the evaluation process, market and product assessment accuracy, platform viability, and final recommendations provided in Customer Service System Replacement Analysis study, created by Newfoundland Power team in May 2003.

META Group is a leading provider of information technology research, advisory services, and strategic consulting. Delivering objective and actionable guidance, META Group's 250 experienced analysts and consultants are trusted advisors to IT and business executives around the world. Our unique collaborative models and dedicated customer service help clients be more efficient, effective, and timely in their use of IT to achieve their business goals. We had 116.5 Million US$ sales Y2002, and currently have operations in 40 countries with 3300 clients Worldwide, which we provide with actionable advice covering the entire IT spectrum. In addition to our core IT technology coverage, one feature that set us apart from other IT research and advisory service providers (e.g. Gartner, GIGA, Forester, Jupiter), is our vertical expertise and coverage of the specific IT solutions for industries such as energy and utilities. More then 120 energy companies worldwide subscribe to our Energy Information Strategies service and we log yearly more than 1500 advisory contacts with energy IT organizations covering a broad range of specific business and technology issues along the energy value chain.

As a member of the Energy Information Strategy team, which contains five dedicated analyst with an average 25+ years executive experience in energy business and IT, I personally provide advice to in excess of 100 energy clients globally on the best practices and technology solutions in the energy retail area, including customer care and billing, handling roughly 300 client inquiries annually. Additionally I am a trusted adviser to all leading Customer Information System (CIS) vendors in the energy space helping them to define product and technology roadmaps, "go to market" strategy and market messaging.

To provide you with a comprehensive assessment of the Customer Service System Replacement Analysis Study, we have formed an interdisciplinary IT team covering all aspects of Customer Service System replacement including the CIS packaged solution, platform viability issues, and tool migrations issues. In addition to myself with primary focus on packaged replacement options, Brian Richardson, Program Director with META Group Infrastructure Strategies Services was retain to cover server platform replacement options, and Mr. Thomas Murphy, Senior Program Director with META Group Integration and Development Strategies was responsible to cover tool migration options. Our short bios and coverage areas are included in the Addendum.

Following are our findings:

Package replacement options (Zarko Sumic):
Based on my knowledge of the energy retail market, business drivers, vendors positioning, product capabilities, market activities, product pricing and contract structures for packaged commercial of the shelf (COTS) software in the CIS space, I find the conclusions and recommendation provided in the Customer Service System Replacement Analysis study, pertinent to packaged replacement option, to be sound and based on accurate interpretation of the relevant market information. I concur with report's assertion that at this point, based on the lack of significant business drivers, complete replacement of the CSS with a packaged COTS CIS is not an optimal solution for Newfoundland Power.

This can be substantiated with:

- Energy retail market restructuring (deregulation) as a main catalyst for CIS replacement has slowed down consequently removing the two most compelling reasons for CIS replacement in North America (customer centricity and competitive energy products time to market)
- The average CIS replacement projects, although streamlined since emergence of the commercial of the shelf (COTS) CIS products, continue to be costly and long. Our survey of the energy industry customer care and billing market and involvement in numerous CIS replacement projects have consistently showed average replacement cost to be $50 US per customer and average implementation duration to be 24 months.
- Due to the financial scrutiny and reduced access to capital, energy companies are much more careful about capital expenditure including IT investments.
- New CIS products, without regulatory mandates or market restructuring imperatives, usually offer only incremental performance improvements that cannot justify CIS replacement cost. Cost benefits analysis and NPV ROI do not favor replacement option.
- CIS solution total cost of ownership (TCO) contributes to the cost benefit analysis but it is never an exclusive reason for CIS replacement.
- In the last 12 months there have been only three major CIS contracts awarded in the North American market placing extreme pressure on the vendors. As a result tier 1 vendors are moving into the already crowded midtier CIS market segment.
- A flat market cannot support the existing number of vendors and it will lead to market consolidation. Therefore, vendor viability is a critically important.
- A flat market has resulted in significant discounting both on the product and service side additionally eroding vendors financial viability.
- Most of the activities in CIS market, rather then replacement, can be characterized as legacy solution extensions aimed at prolonging legacy system life expectancy by dealing with functional inadequacy (e.g. complex billing, credit collection, user interface enhancement). That is achieved in a phased manner through bolting on niche solutions or partially configured COTS solutions.
- Rather then traditional “Big Bang” implementation approach, energy companies are more inclined to “phase in” new products leveraging the existing CIS as long as possible.

Platform Viability (Brian Richardson):

Based on my knowledge of general server market trends, future HP OpenVMS product roadmaps, and fundamental business and cost drivers, I concur with the conclusions and recommendations provided in the Customer Service System Replacement Analysis study.

This conclusion takes into account the following factors:

- HP will manufacture Alpha thru 2006, and Alpha-based systems will be supported until at least 2011
- Longer term, we believe migration from OpenVMS to a more mainstream operating system platform is appropriate; however, there is no immediate or urgent need to migrate
- Accordingly, we recommend a controlled, phased approach, rather than a “big bang” plan (where several infrastructure components are all changed at the same time).
- Near term migration costs are typically several times more than staying on existing infrastructure.
- Newfoundland Power is currently only on low-end to midrange sized Alpha systems, so future scalability issues are negligible.
- Windows is far more mature today than just a few years ago, and there are minimal scalability or manageability issues (particularly when compared with Unix for 4-8 processor systems).
- A key factor is picking an operating system that can leverage “Intel economics” for performance and price/performance.
- New applications are primarily being developed on Windows and Linux (which is currently displacing Solaris, which was by far the leading enterprise Unix).
- We believe that HP will successfully execute on the OpenVMS transition from Alpha to Itanium processors, with minimal disruption to customers.
- However, we believe that OpenVMS on Itanium will not attract significant new ISV interest.

Tool migration options (Thomas Murphy):
Newfoundland Power currently maintains a large portfolio of applications running on OpenVMS and created with Powerhouse. While the company recognizes a need to create a migration strategy (due to concerns over long-term support for OpenVMS) the existing code base has reasonable customer satisfaction and migration costs will be high. Our review of the existing planning documents find the conclusions to be well researched and in-line with current practices.

Issues that should be considered by Newfoundland Power as strategies are set:

- Obtaining skilled developers who are familiar with many of the utilized technologies (e.g. Axiant, Powerhouse) will become increasingly difficult.
- While the vendor continues to support and extend Powerhouse, a limited market will create limitations on vendor's ability to keep pace with technology change
- The package software market is evolving rapidly bringing broader selection of functionality and components that may better fit the companies needs
- A large quantity of "high priority" requests are logged (~220 months of work) Outside of existing functionality, what constraints does the system place on business agility

Given these considerations we believe that:

- Migration towards .net is advisable as a development platform. Developers with RAD and Cobol backgrounds tend to be more successful with this transition than a transition to Java.
- MicroFocus will deliver this year a version of Cobol integrated to .net (Fujitsu already has a product in this space) and this will enable migration of most Cobol code to the .net platform.
- MicroFocus also has tools to help harvest "components" from existing Cobol applications and the migration plans should evaluate the ability to utilize these tools.
- The majority of large enterprises are shifting towards buy vs. build strategies especially for non-core applications (i.e. applications where the business does not differentiate itself) and this would be advisable for Newfoundland Power
- While the transition of developers from Cobol and other legacy platforms to .net is possible, the organization should expect to incur significant training costs. The majority of these developers will take 6-8 months to be fully productive and comfortable in the new environment. The organization should seek to train developers and deploy them on new projects before attempting code migrations.
- Significant talent for doing application migration exists in off-shore development houses located in India. These may offer a much more cost effective option for code migration, however the company must evaluate the ability to manage code created by an outside group and the ability to communicate and deal with time and location barriers.
- Because any action to change will involve a significant effort, the IT group should coordinate closely with business operations to ensure that the new Enterprise Architecture meets long-term business direction and needs.

In conclusion we jointly concur with findings and recommendations in the aforementioned Newfoundland Power Customer Service System Replacement Analysis Study.

Respectfully,

Dr. Zarko Sumic, VP Energy Information Strategies
META Group

Addendum
Analyst Biographies

Analyst Biographies

Mr. Richardson has more than 20 years of experience in systems evaluation, cost/benefit analysis, contract negotiation, systems design and implementation, performance analysis, and strategic planning. Before joining META Group in April 1992, he was assistant vice president of information systems with WR Berkley Corp., an insurance holding company, and was responsibility for coordinating IT nationwide for all locations. Previously, he held various project management positions with several consulting companies, serving financial services clients. Mr. Richardson received a BS in Computer Science from Rutgers University.

Mr. Murphy has more than 15 years of experience in the software development market, developing software and leading product and marketing teams. He is a leading authority on e-business application development and enterprise application integration, especially relating to distributed application infrastructure, component middleware, and application frameworks. Mr. Murphy specializes in integrated development environments suitable for large-scale Web applications, object-oriented analysis and design, repositories, and component object models. He was a contributing author to IEEE's The Handbook of Software for Engineers and Scientists and contributes articles for several industry publications. Prior to joining META Group in September 1999, Mr. Murphy was director of e-business technology marketing for Seagull Software Systems. Previously, he directed product development efforts at ObjectShare (previously ParcPlace-Digitalk) and held various programming, consulting, and editorial positions. Mr. Murphy studied at the University of Utah and Ohio State University.

Dr. Zarko Sumic has more then 27 years of energy industry information technology experience with energy companies, software vendors, and universities. Prior to joining META Group in March 2001, he was vice president and chief technology officer of an unregulated subsidiary of a large energy company, where he was responsible for design, development, and deployment of a new customer information system. Dr. Sumic's background also includes experience with geographic information systems, EMS/SCADA systems, artificial intelligence (AI), and application service provider offerings. He received a B.S. from the University of Split, Croatia; an M.S. from the University of Zagreb, Croatia; and a Ph.D. from the University of Washington, Seattle. Dr. Sumic is a senior member of the IEEE Power Engineering Society and holds three patents in AI and Internet application to power systems.

Appendix C - Customer Service Function Description Internal

Developed in house, the Customer Service System (CSS) provides the Company's primary accounts receivable and direct customer billing for electrical sales. It consists of meter reading, prebilling, billing, cash processing, credit and collection, accounts receivable (AR) maintenance, service orders, system controls and financial controls.

The following is a brief description of major functional aspects of the CSS.

Service Orders (SO)

Of the 308,000 calls to the Call Center in 2002, approximately 50,000 to 70,000 calls utilized the service order features of CSS.

SO provides the ability to capture information regarding the customer, such as their identify and what the customer requires (e.g. the type of service: residential, commercial and whether to supply power to a new service or to an existing account). Also the SO schedules customer requests.

SO then allows users to issue the requests to the field. Users are able to manipulate and update the information already captured as well as enter the field results upon completion of the request.

General Data Maintenance (GDM)

The GDM function provides the user with the ability to edit and update information collected on the customer, the bill account, the premise and the service. In addition, information regarding prior contacts is displayed.

Meter Reading (MR)

During the year, the Company reads approximately 210,000 residential or commercial meters every month. Reading and some initial editing of meter readings is done at the handheld level using the Itron Premierplus 4 System and the G5 Handheld, a 2002 acquisition. The Company is also reviewing radio frequency meter reading alternatives using radio equipped hand-held devices to read automated meter reading (AMR) meters (e.g. Schlumberger Centrons).

On-line Meter Reading functionality within the CSS is limited. Within the CSS, users are able to add and maintain meter reading instructions and other meter reading information not contained elsewhere. They are also able to enter meter readings outside the handheld system and view a 13 month history of meter readings.

Batch processes control and edit the flow of information to and from the handheld.

Prebilling

Prebilling serves two important functions; it applies the read to the account and it conducts a series of edits and checks against that meter reading, the bill account and the premise. If a meter reading was not obtained, Prebill will attempt to apply an estimate for that month. If the read (or estimate) fails one or more of the edits and checks, the premise is sent to a Pending Work Queue (see below for description) for review. Any reads which pass Prebill editing are sent directly to Billing. Prebill occurs primarily in batch, however, on-line prebilling is frequently called when clearing entries from the Pending Work Queues.

Billing

Billing occurs during batch processing. Accounts which have passed Prebill editing are sent to Billing. During Billing, rates are applied, charges are calculated and records updated. Different rate classes allow for calculations of residential charges and more complex (with more options) commercial rates. Once calculated, this information is fed into the Print Bill programs which format the bills for printing or emailing.

There are a number of billing on-line conversations which enhance the normal bill processing. These include a number of billing options, including the Equal Payment Plan (spread payments equally over 10 or 12 months) and Group Billing (combine bills for same customers and issue one bill) and printing options such as multiple copies, email notification and bill on website.

Billing allows for the calculation and debiting of non-electric charges, including one-time charges (e.g. Statement of Account fees), re-occurring non-financed charges (e.g. the corporate charity) and financed charges (e.g., contribution in aid of construction and hot water tanks). These programs are supported by on-line conversations which allow the user to set up, maintain, inquire, cancel or final these charges.

Pending Work Queues

The Pending Work Queue (PWQ) is a function whereby a user can assign, view or complete action requests sent to a particular PWQ by another user or by batch processes. The PWQ can be thought of as an “in basket” in which work a user has to complete is stored. Customer inquiries that have to be passed onto someone else and accounts failing the prebill edits are two examples of the “work” stored on the PWQ. If the work order should be completed by another authority level, we are able to refer it to the appropriate PWQ using a screen within the PWQ conversation.

Cash Processing

Cash Processing allows cash payments to be posted against customer accounts. Approximately 2.4 million payments are processed per year broken down as follows:

- 20% are made via the mail
- 19% are paid in person at Company offices
- 32% are paid via telephone banking
- 17% are paid at a Bank or other financial institution
- 8% are paid via Preauthorized programs
- 4% of payments are received directly from government/crown corporation assistance programs

Payments received via the mail or paid at financial institutions are encoded through the Creditron Remittance Processor, implemented in 2000. The remittance processor reads bill stubs and transmits a file to the CSS. Payments received via front-end cash also are batched and a file is transmitted to the CSS at the end of the workday. When the remittance processor or the Cash Register system cannot be used, the CSS provides a screen for data entry of payments.

These payments are processed by batch overnight and applied against particular charges based on a predetermined priority.

The Company accepts cash, cheques (including post-dated), electronic payments and money orders. It does not accept VISA at this time.

CSS supports the cash function by providing screens to set the cash processing date, input non-scannable payments, correct out of balance batches and correct cash payments that are rejected at posting time.

Credit and Collections

The current Credit and Deposit policies and procedures are enabled through a combination of on-line and batch processes. Batch processing procedures assess the balances outstanding and automatically generate reminders on electric service bills or generate individual notices and letters. Users also have the ability to capture payment commitments made by the customers. When customers fail to meet a commitment or the conditions outlined in these Notices/Letters, the account is brought to the attention of Credit staff via a Pending Work Queue. Credit staff follow-up on the account by attempting collection and making suitable payment arrangements. When all attempts have been exhausted, serious collection action may be taken (e.g. disconnection of service).

The CSS also provides the ability to calculate, bill and manage Deposits.

Accounts Receivable Adjustment and Inquiry (AR)

The AR component of CSS consists of a series of conversations which contain either a history of like financial transactions or group of conversations allowing users to make these transactions. In many instances, conversations are bundled together to make a work process. For example, to inquire upon a charge, the user may look at the charge details, payments applied against that charge and the transfers of that charge - all within the same conversation.   Users are able to view the details of charges created, credits applied, transfers, refunds and bills issued. Users are able to adjust charges, issue credits, transfer charges and credits, and issue refunds. Users are able to issue and approve adjustments within predetermined approval limits. Refunds, which require approval regardless of the position, are the exception to this rule.

There also are a number of AR nightly batch processes. The majority of these processes are preventative controls which ensure bill accounts, bills, charges, payments, etc. are balanced. The Transfer Adjustment batch process mimics the on-line conversations and transfers credit and charge balances automatically on terminated accounts, to active accounts.

Appendix D - Customer Service System Technical Description Internal

Online Environment/User Interface

CSS is a thin client GUI application comprised primarily of Cognos' Axiant 3.0 on the client PC and Powerhouse 820.d3. There are calls to OpenVMS COBOL version 2.4 and Oracle's ProCOBOL version 1.8.51.0 on the OpenVMS server for primary business logic execution.

Embedded Software

PC Lookup Correction (v1.10) from COMDATA Services Ltd. is the software used to ensure mailing addresses comply with Canada Post standards.

Communication with a number of windows software programs is enabled via DDE (Dynamic Data Exchange). This includes Microsoft Excel, Visual Basic program and integration with Aspect system (Screen Pop). No OLE, ActiveX or custom DLL's are used.

Architecture Principles

Screens – A series of related screens to perform a single function such as to "Issue Credit Adjustment" is called a "Conversation". Control of which screen is displayed next within a conversation is determined by the application and is based on user input and pre-programmed routing within the application.

Database updates are initiated through the following sources:
- The Axiant on-line forms will perform updates for specific conversations. The form is put into edit/entry mode for data entry and an update transaction is executed when the user initiates a save/update operation.
- The calls to the COBOL back-ends for specific conversations perform some of the more complex business logic and database updates. These routines are executed real time.

General Navigation – The system utilizes a "Standard Account Data" area whereby an account is retrieved and standard account information such as name and bill account etc. are displayed on the top two lines of all screens in all conversations thereafter. The retrieval of an account is required with few exceptions to run a conversation.

A conversation may be initiated via menus or a four-character code enterable from any screen. As well, dropdown boxes can be used to access menus and groups of conversations.

Suspend/Resume Navigation – This navigation technique utilizes a Visual Basic module that resides on the client PC. This code interacts with the core CSS software and tracks the screen calls for the user.

- *Suspend* function allows the user to leave a conversation in progress and start another conversation to accomplish a different (or similar task). The user can suspend up to 6 times within the application and have multiple levels of conversations open within each suspended session.
- *Resume* function, when activated, will bring the user back through the conversation levels to each originating suspend point starting with the latest in the stack and returning until the stack is cleared.

Read Only Environment – This process is controlled by the application. The computer operator has an option to bring down the online CSS application and re-start it with no updates allowed. The procedures set a parameter flag to “Y”. The online conversations are designed to recognize this flag and when a “Y” is recognized, the conversation will not allow updates to the database. This allows for information viewing and therefore some simple Call Center activities to continue during running of nightly batch procedures.

Reporting – Some limited reporting within the online environment is available via a batch launch interface (Powerhouse Quiz). The reports are sent directly to the printer defined by the user’s profile. As well reporting from the desktop is performed with tools such as Microsoft Access, Microsoft Excel and Cognos Impromptu.

Demographics:
Program Information:

Axiant:
- The total number of Axiant programs -165
- Total lines of Axiant code - 250,000

COBOL:
- Number of online COBOL programs - 67
- Total lines of online COBOL code - 95,000

Response Time: The majority of on-line forms have a sub second response time. Specific “heavy” functioning forms could have a response time up to 4-6 seconds at times.

Availability: The on-line availability service level agreement requires at least 99% availability, which is currently being met. The on-line system runs in update mode from 8:00 am to 8:00 pm Monday to Friday with extended view-only capabilities available outside this window.

Batch Environment

The batch processing is performed to complete high volume transactions and larger reporting requests. (e.g. post readings, post cash payments, edit accounts, calculate late payment charges, calculate forfeited discount charges, calculate bills, print bills, perform audit checks, populate collection queues, issue form letters, produce daily, weekly and monthly reports etc.)

There is a regular nightly batch “window” (8pm - 8am daily) during which full online system availability is limited. As well there are weekly, monthly, quarterly, yearly and numerous specialized processes. Nightly and most other batch processes are computer operator attended.

The batch technical architecture consists of the following software/versions: OpenVMS COBOL 2.4, Oracle’s ProCOBOL 1.8.51.0.0, Powerhouse 820.d3 QUIZ, QTP, and OpenVMS DCL.

Embedded Software

PC Lookup Presort v1.04 from COMDATA Services Ltd. This is software to sort mail to obtain postal incentive rates.

Architecture Principles

Batch Submission and Control Process - Batch job submission and error handling processing is an in-house developed batch processing architecture (written in DCL) utilizing control, error reporting and check-point architecture. OpenVMS job control features such as “Synchronize” commands are utilized as well.

Load Programs - The batch windows frequently utilize “load programs” to perform data updates. Many jobs, rather than update the database immediately, stream updates to the same table into an RMS file. These files are then “loaded” into the database immediately after the “read only” job is completed. This technique was originally used to resolve performance problems when the system was first implemented.

“A” and “B” jobs – To address performance concerns, cash posting and other types of transactions are separated into “A” and “B” jobs. The “A” job for example, posts all cash for accounts being billed that night. The “B” job posts the rest of the cash. The idea is to run the comparatively very short “A” job before billing so that the nightly billing job can get started as early as possible. Meanwhile the “B” job can be run while billing is processing.

Demographics:

Program Information

Powerhouse:

- The total number of batch powerhouse programs by type:
  - QTP -120
  - QUIZ - 520
- Total lines of batch powerhouse code by type:
  - QTP - 8,500
  - QUIZ - 45,000

COBOL:

- Number of batch COBOL programs - 276
- Total lines of batch COBOL code - 430,000

DCL:

- Number of DCL command procedures - 1400
- Total line of DCL command code - 60,000

Batch Window Length: The full batch average window length is 10hrs and 20min. This is from the start of the first job to the last read-only report each day. The online system is made available much sooner, however the system response time is often too degraded for general call center use till full batch is completed. If the full batch window goes beyond the 8:00am start time for call center opening, some read only jobs are sacrificed to ensure performance is maintained.

Bills Printed:

- 192,000 bills are printed per month.
- On average 10,100 bills are printed per night assuming a 19 cycle billing period.
- On average there are two nights per month (non-reading days) where less than 3,000 bills are printed.

Collection Notices and Form Letters:

- 14,600 Payment Reminder Notices are printed per month. About 730 per day.
- 10,500 Delinquent Account Letters are printed per month. About 525 per day.
- 1,400 Various form letters are printed per month.

Transactions Posted:

- Approximately 200,000 cash transactions are posted per month or about 6,500 per day.
- 205,000 readings are posted per month or about 10,800 per cycle day.

Batch Support Calls:

- There are approximately 5 call-outs (operator to on-call application support person) per month.

Data Architecture

The current data model for the CSS is fully documented and is based on a Customer/1 model, which was highly customized when the system was developed. The separation of Customer, Customer Location and Bill Account is preserved. The data is relatively normalized and modeled accordingly.

With few exceptions, all customer related data is stored in one Oracle database residing on an OpenVMS server. RMS files are primarily used to hold interim transactional data, control data, some reporting information and to load database tables during batch processing.

File System:

Data of an ad hoc, reporting, and batch processing nature is stored in the OpenVMS RMS file subsystem. The RMS files are a mixture of sequential, indexed or relative. Powerhouse sub-files are also utilized.

RMS file demographics:

- Approximate number of files - 1350
- Approximate size - 8,300,000 blocks (VMS block = 512 bytes – approx. 4 gigabytes)
- Approximate number of Powerhouse sub-files - 410. The remaining files are normal OpenVMS .DAT, .TXT or .BCK files

Database Management System:

The primary customer application data is stored in an Oracle Server Enterprise Edition (version 8.1.6.0.0) database instance, residing on an OpenVMS server. The Oracle SQLNET protocol is used for client connections.

Database Tuning and Monitoring Tools:

Oracle DBMS tuning routines are developed in-house, using DCL procedures utilizing OpenVMS operating system features, calling SQL scripts, and supplemented with Oracle Enterprise Manager running on the windows platform.

Program Information:

DCL:

- Number of DCL command procedures - 150
- Total line of DCL command code - 8500

SQL:

- Number of SQL procedures - 40
- Total lines of SQL command code - 15000

Database Backups:

In-house written DCL procedures utilizing OpenVMS operating system features are used to back up the Oracle DBMS. Database backups consist of daily hot backups with archive logging, and weekly cold backups and exports. The database is first backed up to disk and then the disk backup is backed up to tape and stored offsite.

Program Information:

DCL:

- Number of DCL command procedures - 20
- Total lines of DCL command code - 2700

Architecture Principles

Business transaction integrity is maintained via transaction level read consistency ("set transaction read only") and statement level read consistency. There are coded "for update" clauses that acquire row level write locks.

Database level triggers are utilized to perform data validation and editing during the online window. Database constraints are utilized to enforce primary keys, and data validation. A limited number of foreign keys constraints are used to enforce referential integrity.

Stored procedures are used to a limited degree to perform data validation and editing.
Two Oracle communication listeners are configured to improve database connection performance.

Demographics

- Approximately 300 named users
- Approximately 100 concurrent users daily
- Approximately 6500 database connections per day
- 170 database tables
- 209 Indexes
- Database is 26 gigabytes in size with growth at 2.5 gigabytes of data per year with a purge of 2 gigabytes annually
- Database Reserved Memory is 1.438 gigabytes

Security Architecture

Multi-level security features have been developed to prevent unauthorized access at the application or database level. These include application, DBMS and Operating System level security.

Configuration:

Operating System Security: OpenVMS user names and passwords are required to access CSS. The user name and password is validated and based on the users, specific access is given via VMS identifiers. This sets the level of access allowed on the system.

Application Security: The CSS application has security features built in through code. It has security tables set up in the database that define functional groups and the individual screens that are accessible to the group. An administrator assigns users to a group. This is a function within the application. Code is written to identify the user logged in and the group they belong to. This is maintained throughout the session. As the user navigates from screen to screen common code is executed to ensure the user can access the particular form. If not authorized, a message is presented to the user as notification that access is denied.

Database Security: Application level database security is enforced through the operating system using trusted connections. Oracle table level security is enforced through Oracle password protected roles. Database views are used as a security technique to protect sensitive data.

File Security: File security is controlled with VMS identifiers. The identifiers are granted during application start-up and are only available while running the application. If access is required outside the application a separate identifier is assigned to the user and is restricted based on the users requirements.

Reporting Environment

Production Reporting is handled through the on-line environment and through the nightly batch processing. Reports are developed through Powerhouse Quiz and COBOL on the OpenVMS platform and are executed either from the online environment or in the batch environment in a scheduled manner (nightly, weekly, or monthly).

Customer Service Information System (CSIS)

This is a small reporting application written in DCL on the OpenVMS platform. It consolidates some of the production reports generated during batch processing into a central area for users to print via a menu. The menu has various options that print the pertinent report based on the user's logon id.

Ad Hoc End User reporting:

There is no dedicated reporting database or data warehouse available to users. All reporting is generally done from the production data source. From time to time the Disaster Recovery/Test server is refreshed with the current production database to support intensive reporting efforts. This takes pressure from the production machine and allows the users some flexibility in when and how the reports are developed and executed. Users primarily use Cognos Powerhouse Quiz on the OpenVMS platform as the ad-hoc reporting tool. Some users utilize the Cognos Impromptu GUI report writer tool on the windows platform. The company has standardized on the Cognos BI tools for its reporting needs to date.

The total number of end user written reports is 899.

The total number of Powerhouse report programs by type:
- QTP - 10
- QUIZ - 900

Total lines of Powerhouse code by type :
- QTP - 850
- QUIZ - 31,000

OLAP reporting:

An OLAP cube is created from daily revenue files generated from our nightly batch processing for billing/revenue analysis and the Cognos Power Play product is used.

Development Environment

There is a dedicated development OpenVMS server call “ORION” that is used to support all development and maintenance activities for the CSS. The Axiant Development Tool Set is installed locally on each developer’s PC. There are various in-house written DCL, Powerhouse QTP, Quiz and Quick screens to manage programs and transfer data. “Synergex PVCS version 6.0” is utilized as a source code manager for the CSS.

Axiant is a repository based development environment. There is a development repository, which is refreshed from production periodically, and there is a main production repository. All development work is maintained within the development repository on the development server.

Once tested and signed off, the changes are exported from the development repository and imported into the production repository where a recompile is initiated to produce production executables.

Because this is a thin client application, all executables are on the server. The production executables are also maintained on the development server but are migrated to the production server. The production executables are segregated from the development environments on the development server.

There are various in-house developed routines written in DCL and Powerhouse that refresh development databases and extract pertinent data from the production database and populate one of many development databases. This process executes a series of Quick screens, QTP and Quiz code to perform its work.

The Disaster Recovery/Test server is used to execute large-scale tests if warranted. Typical use would be to perform upgrade testing, performance testing or major functional testing.

Customer Accounting Testing System (CATS): This is an in-house developed testing environment that allows Customer Service personnel to check and test changes to customer electricity rates. It allows the users to modify the rates Newfoundland Power charge to customers and put them through the bill calculation and print bill functions from the batch processing procedures. This allows the Customers Service group to assess impact and accuracy for customer bills prior to implementing any changes. The environment is a combination of Axiant/Powerhouse, COBOL and DCL.

Program Information:

Powerhouse:

The total number of batch powerhouse programs by type:

- QKS - 36
- QTP - 13
- QUIZ - 13

Total lines of batch powerhouse code by type :

- QKS - 3,500
- QTP - 550
- QUIZ - 340

COBOL:

- Number of batch COBOL programs – 15
  (utilizes existing CSS batch programs)

DCL:

- Number of DCL command procedures - 85
- Total line of DCL command code - 8,000

Training environment:

The training environment is established on the Disaster Recovery server. The data is loaded/refreshed periodically through custom written routines. When the Customer Account Representatives need training for new modules or update training on existing modules, they can be accommodated here.

Deployment:

There are two aspects to the deployment process:

- While this is a thin client application, all executable code is moved to the production server through a migration routine. This routine is written in DCL and identifies the files to be moved to production. The DCL routine is then put in a batch queue and released at the appropriate time. When it executes, it copies the files identified from the development server production area, to the actual production server executable area.

- The second aspect of deployment is getting the modified forms on the users desktop. This is generally done through Microsoft's Systems Management Server (SMS). All identified clients receive the updates automatically.

Hardware Infrastructure

CSS runs in a 2-tier architecture (client and application/database server) for production with a duplicate hardware infrastructure for disaster recovery. A separate hardware infrastructure supports development and testing efforts. The disaster recovery environment is also used to support full size functional and performance testing. The following describes the existing hardware infrastructure:

<u>Production Application/Database Server (DRACO):</u>

- Type: Compaq Digital Alpha Server 4100
- Processor: 3 5/533
- Memory: 6 Gb Ram
- Disks: Internal 7 @ 9GB 1@ 18GB 3 @ 4.3GB SAN 18@36.4GB
- Controller: 1 SE SCSI, 2 FC Controllers, 1 Raid KZPSC 1 DE500 10/100 Ethernet
- Tape Drive: TZ88, 2 DLT 7000
- TCPware version 5.4-3

<u>Disaster Recovery Application/Database Server (CORVUS)</u>

- Type: Compaq Digital Alpha Server 4100
- Processor: 3 5/ 533
- Memory: 6 Gb Ram
- Disks: Internal 8 @ 9GB 1@ 18GB 1 @ 4.3GB
- SAN 18@36.4GB
- Controller: 1 SE SCSI, 2 FC Controllers, 1 Raid KZPSC 1 DE500 10/100 Ethernet
- Tape Drive: TZ88, 2 DLT 4000

Development/test Server (ORION)

Type: Compaq Digital Alpha Server 4100

- Processor: 2 5/ 300
- Memory: 1.5 Gb Ram
- Disks: 17 @ 9 Gb, 1 @ 4Gb total 157Gb
- Controller: 1-10/100 ETH,2 SE SCSI, 1 Raid KZPSC 1 DE500
- Tape Drive: 1 @ TZ88, 1 @ TZ87

Typical Client Desktop Configuration:

- Platform/OS: Windows NT
- Type: Dell Optiplex GX110+/L Pentium III
- CPU: 733
- Hard Drive: 12.4 gigs
- Monitor: 17 inch Dell Monitor
- Memory: 256 MB

Appendix E - CSS Application Integration Description Internal

Refer to a diagram below in Appendix A CSS Integration Model, which graphically depicts the current integrations with the CSS application.

Integration with Other Internal Applications

Hand Held Meter Reading (Itron's Premierplus 4)

The CSS interfaces with a third party hand held meter reading application, "Itron's PremierPlus4 (version 2.8.01)". This interface performs data file transfers to and from both applications. Files of meter readings taken during the day by meter readers are downloaded to the PremierPlus 4 system and sent via FTP to a CSS data area, for processing by the CSS nightly batch procedures. Files of meters expecting to be read on the following reading day are sent (via FTP) from a CSS nightly batch procedure to the Hand Held Meter Reading server.

Cash Remittance Processors

The Cash Control section processes all payments from the bank and the mail through the remittance processor "Creditron RP$2000 (version 5.07.0135)". The interface with the CSS is a file based transfer. A file of all entered payments is created daily, copied to and processed by the CSS nightly batch.

Cash Registers

Each area office has the capability of accepting payments in person. The payments are processed through cash registers and included in a file. The interface with the CSS is a file based transfer. Each cash register transmits this file by 3:00 pm every day. These payments are included with payments from other sources (eg. remittance processor) and posted to customers' accounts during the CSS nightly batch processing.

Weather Normalization

Weather normalization is an in-house developed application. This system tracks actual and normal temperatures and wind speed data. This information is used by the CSS for bill estimation and responding to customers' high bill inquiries. The interface with the CSS is through a data file transfer. Files of updated weather information are sent to the CSS daily and processed by the CSS batch.

Internet Application: Customer Account Inquiry

An in-house custom developed Customer Account Inquiry function is available to customers via the Company's corporate Internet site. The CSS nightly batch process downloads a data file of all active customer billing and payment data each night. A separate staging database (WEB Oracle 8.1.7 on NT) is populated using these files. This database is then used by the external Internet application, the internal Intranet Customer Inquiry application and the Call Center Aspect CTI application.

Objectif Lune Document Distribution Modules

The CSS batch environment interfaces with a third party electronic document distribution line of products. This line of products provided by Objectif Lune includes "PlanetImage (version 3.3.0.251), PlanetWatch (version 3.3.1.683), PlanetPress (version 3.3.1.737), PlanetSearch (version 3.5)".

The "PlanetWatch" and "PlanetImage" modules are used to co-ordinate the physical printing and electronic presenting of the customers electric bill. The nightly CSS batch process sends the print file of customer's bills to the "PlanetPress" server. On a daily basis, a current file of customers' email addresses for those on eBill is sent to the "PlanetPress" server. "PlanetPress" formats the data in a predefined form and coordinates the printing via the IKON printer. For those customers signed up on eBill, this product will notify them via email that their bill is ready for pickup online through the Company's corporate website. Here, customers can log in to pick up their copy of their electrical bill in the Customer Inquiry application.

Customer Account Inquiry

The Customer Account Inquiry application is an in-house, custom developed, browser based function. This application is available to customers via the Company's Internet web site and is also available to internal employees via the corporate Intranet site. The application utilizes the WEB staging database in both cases

Disconnect for Debt

This is an in-house, custom developed, browser based, application used to list customers due for disconnection. It is used after business hours by the System Control Center and others who are responsible for organizing line crews to disconnect/remove meters for non-payment. The application accesses the CSS database in a real time mode for customer, location and current balance information.

Call Center Technology

The Customer Services Call Center utilizes a third party Computer Telephony Integration product called "Aspect Automatic Call Distribution System (version 3.1)".

The application is integrated with the CSS utilizing a "screen pop" to the CSS based on bill account number entered by the customer on the phone or phone number lookup. This application utilizes the Customer Internet database (WEB) in real time for Customer Bill Account, Meter Number, payment and phone number information for interactive voice response and data directed routing.

Meters (MES)

The in-house custom developed Metering Equipment system is used to record and control electrical meters that record electric consumption. The CSS accesses the Meter database in real time in read-only mode for both online and batch processing. The meter multiplier and installation information is retrieved and used in the calculation of electrical consumption. Meter readings and dates for metering installations, which have had a change to their configuration, causing a recalculation of the installation multiplier, are recorded in the Meters application. This information is sent daily to the CSS via a data file transfer method and uploaded to the CSS database. The annual Compliance Sample Orders and Government Retest Order processes create a file used to insert service orders in the CSS database. A file is sent from the CSS to the Meters application to update the meter inventory based on completed service orders in which a meter was installed at a customer location.

Street Lighting

The in-house custom developed Street Lighting system manages information regarding area lighting facilities, including assembly, installation, removal of light fixtures and underground wiring. It has various functions for tracking specifications (type, size, style), installations (install/remove dates, billing effective/expiry dates, location of street light for customer billing). The CSS accesses the Street Lighting database real time in read only mode in both the online and batch environment for the purpose of area light inquiries and billing customers for area lighting services.

The Street Lighting system directly accesses the CSS database in read-only mode for customer, location and service order information.

Poles

The in-house custom developed Poles System is used to record installed pole characteristics. The CSS accesses the Poles database directly in read-only mode for the purpose of billing customers for the use of the pole for dedicated area lighting. The Pole System also directly accesses the CSS database in read-only mode for customer, location and service order information.

Problem Call Logging/Outage Management (PCLS)

The in-house custom developed problem call logging system was developed to record calls from electrical customers experiencing outages. The application maintains a direct database access to the CSS database in read-only mode to customer, location and service information. CSS also has direct update access to the Problem Call Logging database. A screen in CSS allows call center users to enter problem calls directly (a similar screen exists in PCLS).

Financial Application - Microsoft Great Plains e.Enterprise Suite

The Company’s financial application, Microsoft’s Great Plains e.Enterprise version 6.08, is integrated with CSS through a batch oriented point-to-point data file transfer.

A data file of vendor numbers from Great Plains e.Enterprise is sent to a CSS data area, uploaded and used by the on-line environment to validate vendors for the various financing programs available to customers. This file is uploaded to the CSS database on a nightly basis through the nightly CSS batch procedures.

The nightly CSS batch procedures send RMS data files of daily and monthly financial transactions, customer refunds and petty cash recorded in the CSS to the e.Enterprise application data area for uploading by the e.Enterprise integration manager.

Various CSS financial reports are created by the nightly batch procedures and copied to the financial area.

Integration with External Organizations (B2B)

COMDATA Services Ltd

Electronic data files are sent to CSS on a monthly basis with valid addresses and postal codes from Canada Post. These address files are used by CSS on-line conversations to correct addresses. The postal code files are used by the CSS nightly batch billing process to add walk routes information and sort bills and other correspondence for mailing. PC Lookup Correction (v1.10) software is called in the CSS on-line environment. The PC Lookup Presort (v1.04) is used in the CSS batch processing environment to sort mail to obtain postal incentive rates.

Newfoundland and Labrador Housing Corporation

This Crown corporation provides an electric service subsidy to its clients. An electronic file of the subsidies available per customer location is received three times monthly from the Corporation. The CSS batch process creates a file of electrical subsidies actually credited to customers to be sent back to the Housing Corporation.

Department of Social Services

The provincial Department of Social Services, when necessary, will deduct electric service payments directly from a client's assistance cheque. A file of these direct payments is received and processed twice per month and posted with cash from other sources (eg. cash registers, remittance processor).

The Royal Bank of Canada

Electronic payment files flow back and forth between the CSS and the Royal Bank daily. This includes electronic files, such as ebanking and telephone payments, which are received and processed by CSS nightly batch. Newfoundland Power also offers customers the option of preauthorized payment withdrawal. This file is created by the CSS batch daily and sent to the bank for payment processing. Electronic files of rejected preauthorized payments also are processed by the CSS nightly batch.

Large Client Electronic Billing

An electronic version of the bill for one of the Company's larger clients is emailed directly to the client. As part of CSS weekend batch processing, a file of the client's bill information is created, converted to a Microsoft Excel file and emailed directly to the designated client contact.

Miscellaneous User Developed Applications

There are a number of user developed applications and reports which supplement and complement the existing CSS application. These systems have been designed to retrieve information from CSS and store additional information pertaining to the subject area. User developed applications use MS Access to perform automated balancing procedures for cash payments, month-end revenue reporting, and credit summaries, etc. User developed reports exist in Powerhouse Quiz on the OpenVMS platform and MS Access as well as Cognos Impromptu/PowerPlay via ODBC on the windows platform.

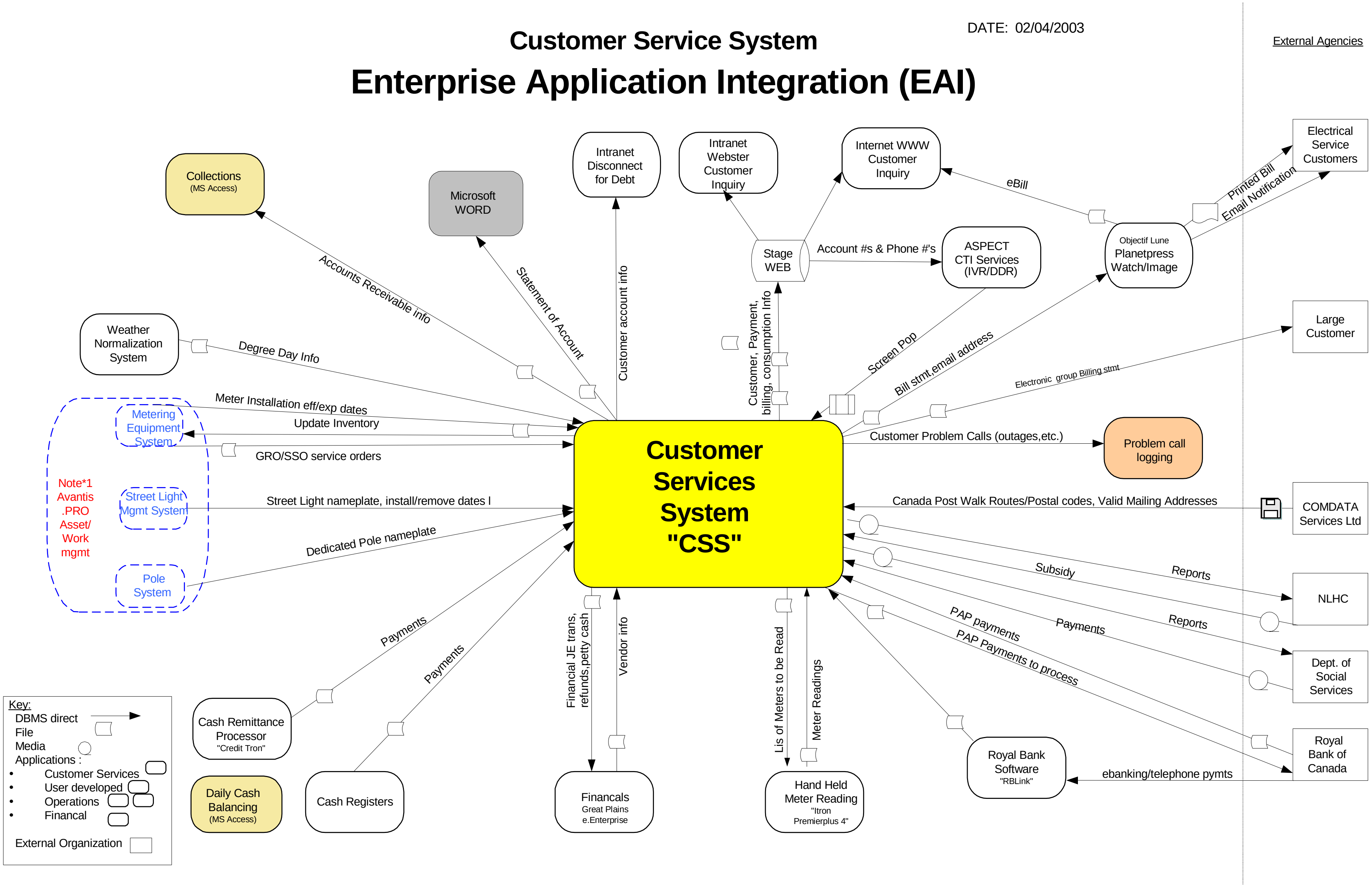
Future Integration

Avantis.PRO (Metering, Street Lights, Poles and Customer Driven Work Management)

The Metering, Pole, and Street Light applications are scheduled for replacement as outlined in the OpenVMS migration plan. A third party enterprise-wide asset management application from Invensys, "Avantis.PRO (version 3.2)", is being implemented in the 2003 - 2004 timeframe. The metering data and possibly the area light assets will be placed into this application residing on the Microsoft platform with an Oracle database. The CSS application will have to interface with this data.

Work management activities (customer driven work) will be implemented in the Avantis.PRO application. The CSS application will generate customer service orders that will create work orders in the Avantis.PRO application. The CSS application must be able to query the status of service orders/work orders within the Avantis.PRO database inside of the CSS online user interface.

Appendix A - CSS Integration Model



Customer Service System

Enterprise Application Integration (EAI)

DATE: 02/04/2003

Appendix F - Utility Survey Description
Internal

Survey of Canadian Utilities
March 2003

Introduction

Newfoundland Power is conducting research on Customer Information Systems (CIS) in use at utilities across Canada. Newfoundland Power is currently examining several options with regards to the future of its CIS system including partial package replacement via commercial “bolt-on” products, and custom re-coding of the application. To aid the decision-making process, Newfoundland Power is interested in learning what its peers have done, or are doing, in this important business/technology area.

Newfoundland Power has engaged **xwave**, a Canadian information technology services company, to facilitate this survey on their behalf. Survey responses, as well as questions or comments about the survey, should be directed to the following:

Andrea Marshall
Business Analyst – **xwave**
St. John’s, Newfoundland
Phone: (709) 570-1900
Fax: (709) 726-1831
Email: Andrea.Marshall@xwave.com

Newfoundland Power greatly appreciates your cooperation in the completion of this survey.

Survey Results

Newfoundland Power will summarize survey results and distribute to respondents, if desired. Information provided to Newfoundland Power will be included in the summary only if authorized by the respondent (see below). In addition, summary information will be confidential, i.e. individual utilities will not be linked to specific response information. Rather, responses will be grouped, e.g. *“ Five out of ten utility companies surveyed currently print their own electric service bills”*.

Please answer the following questions pertaining to survey results:

1) Would you like your responses included in a shared survey summary? Yes / No ____

2) Would you like to receive a survey summary? Yes / No ____

Contact Information – Person(s) Completing Survey

Name		Name	
Position		Position	
Company		Company	
Phone		Phone	
Email		Email	

Part 1: Customer Information Systems

Objective: To profile the current customer information solutions of select Canadian utilities and identify the future directions for these solutions.

Part 1-A Customer Information Systems (CIS)

Number of internal staff in Customer Service: ____
Number of internal staff in Information Technology: ____

Our CIS offers:

CIS Component	Developed In-House or Vendor (if Vendor, give Vendor name), N/A	Application Name	Version	Date Installed
Service Order Processing				
Customer Data Maintenance				
Customer Billing				
Specialized Billing (e.g. industrial billing, group billing)				
Bill Printing				
High Bill Inquiry/Analysis				
Credit and Collections				
Accounts Receivable				
Cash Receipt/Point of Sale				
Analysis/Decision Support Tools				
CRM				
Field Action Processing/Tracking				
Area Lights/Special Products Tracking				
Load Management				
Web self service				
Electronic bill viewing				
Other:				

Additional Information/Comments:

___

___

___

Part 1-B Specific Applications of Interest

1. Do you currently offer customers onsite Cashier facilities for bill payment? **Yes/No** ____
2. If Yes to question 1, do you utilize commercial cash receipt/point of sale software (i.e. as opposed to software developed in-house)? Yes/No ____
3. Does your company have authorized agents who collect payments on your behalf (e.g. drug stores, supermarkets, etc.)? **Yes/No** ____
4. Do you currently print and mail your own Electric service bills? **Yes/No** ____
5. If Yes to question 4, do you utilize commercial printer software to format bills? **Yes/No** ____

If you answered *Yes* to either question 2 or 5, please complete the following table.

	Commercial Cash Receipt/ Point of Sale	**Commercial Print Bill**
Application Name and Version		
Vendor Name		
Vendor Location		
Vendor has Canadian offices? (Yes/No)		
Utility's Cash Receipt Hours of Operation (e.g. accept payments 9 – 5, 8 – 8, 24 hrs, etc.)		▨
Utility's Volume of Daily Transactions		
Hardware Components (e.g. PC, optical scanner, cash drawer, printer,etc.)		
Was an RFP Issued for this purchase? (Yes/No)		
What was the main reason for selecting this vendor? (Cost, Functionality, Usability, Compatibility)		
Original Purchase Date		
Overall Evaluation of the product (M – Meets needs; E – Exceeds needs; D – Does not meet needs)		

Additional Information/Comments:

Part 1-C Technology Profile

On what infrastructure platform does your CSS operate?

Platform Component	**Modes of Operation**		
	Online	**Batch**	**Report Processing**
Hardware (e.g. Compaq Alpha, AS 400, Windows servers, etc.)			
Operating System (e.g. Unix, Windows, OpenVMS)			
Database Management System (e.g. Oracle, DB2, file based, relational, etc.)			
Development Tools (VB, PowerHouse, etc.)			

Additional Information/Comments:

____

____

____

____

Part 1-D Future Plans/Directions

What are your future plans with regards to your CSS system? In particular, are any of the following activities planned:

Activity	**Planned? (Y/N)**	**Brief Description**
Enhancement/extension of legacy application.		
Full replacement.		
Re-Platform.		

Additional Information/Comments:

____

____

____

Part 2: Other Applications in Use

Objective: To gather high-level information regarding applications being used by other Canadian utilities.

Using the following table, please indicate which of the application types your organization currently uses. Of these applications, please note whether they were developed in-house or purchased from a vendor. For purchased applications, please include vendor name, as well as application name and version.

Application Type	**In-Use? (Y/N)**	**Purchased or In-House?**	**Vendor**	**Application Name and Version**
Outage Management				
Asset/Facilities Management				
Meter Equipment Inventory				
Work Management				
Human Resources Management				
Financial Management (GL/AP/AR)				
Materials Management – Purchasing and Inventory				

Additional Information/Comments:

Appendix G – OpenVMS Research Project Xwave Report External

xwave, An Aliant Company
ISBU Enterprise Server Team
Higgins Line
St. John’s, Newfoundland
Telephone: (709) 724-7500
Fax: (709) 724-7555

OpenVMS Environment Research Project

FOR

NEWFOUNDLAND
POWER
A FORTIS COMPANY

July 28, 2003

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1.0 EXECUTIVE SUMMARY

Newfoundland Power Inc. (“the Company”) operates an integrated generation, transmission and distribution system throughout the island part of the province of Newfoundland and Labrador. The Company serves approximately 220,000 customers in more than 600 communities, representing 85 per cent of all electrical consumers in the province.

Newfoundland Power’s vision is to **be a leader in electrical transmission and distribution services in North America.** To support this vision and achieve business goals, the Company’s IS Department has established an “I.T. Roadmap” to identify and prioritize deployment of IT solutions. These solutions will provide increased operating efficiencies, additional functionality and will ensure suitable technology to support new business growth.

A critical factor determining the successful use of IT at Newfoundland Power is the availability and reliability of applications and supporting infrastructure. The application can provide the greatest functionality possible, but if the infrastructure, especially the server, is not available or does not provide adequate performance, the solution will not provide business value.

Newfoundland Power currently utilizes the OpenVMS environment for a number of its corporate applications including the Customer Service System (CSS). OpenVMS has been the primary application development environment for more than 15 years and has offered reliability and stability. However, Newfoundland Power is at a critical juncture with respect to selection of a computing platform for much of its core production environment.

The primary objective of the OpenVMS Research Project (the Project) was to investigate the prevalence and future direction of the OpenVMS environment. These research findings are intended to assist Newfoundland Power in making a decision regarding whether to migrate from the OpenVMS environment. A second objective of the Project was to identify high-level technical architecture alternatives to maintain the current level of stability, reliability and availability.

Information for the Project was gathered from both primary and secondary sources. Interviews and questionnaires were used to gather information from industry consultants, hardware and software vendors, OpenVMS customers and Newfoundland Power staff. Secondary sources included white papers, research opinions and strategy documents.

While conducting the research for the Project, **xwave** discovered the following key findings:

OpenVMS Environment: Various generations of OpenVMS have been available since 1977.There are more than 30 OpenVMS customers in Atlantic Canada.

OpenVMS at Newfoundland Power: Newfoundland Power has six OpenVMS servers ranging in age from three to seven years. The AlphaServer 4100 server line that Newfoundland Power runs OpenVMS on has been discontinued and spare parts have to be purchased from third party vendors. One Full Time Equivalent (FTE) is required to support the six OpenVMS servers compared to two FTEs to support the Intel environment consisting of 57 Compaq servers. While it is not always appropriate to assume a one-to-one relationship between OpenVMS and Windows server support, total server support effort would likely be reduced by migrating from OpenVMS to Windows or UNIX. The OpenVMS platforms provide a highly stable, reliable and available environment for the applications residing on them. However, they require a significant level of manual care and intervention, which adds to the resource requirements for the servers. By the end of 2003, all the applications on the OpenVMS servers except CSS will have been replaced.

OpenVMS Roadmaps: Hewlett Packard has stated that OpenVMS will be sold on the AlphaServer technology until at least 2006, and will be supported on this platform until at least 2011. The AlphaServer will be marketed at least until 2006 and supported for an additional 5 years. Hewlett Packard will release a production version of OpenVMS on the Itanium technology around 2004-2005.

OpenVMS Revenues and Shipments: The Gartner Group, a leading IT industry consulting firm, expects revenues from new sales of OpenVMS in 2006 to decline to $36 Million from $806 Million in 1998. During the same period, Windows NT/2000 will rise to $16.3 Billion from $6.9 Billion and Solaris to $9.9 Billion from $4.9 Billion. OpenVMS shipments are projected to decrease from 19,000 units in 1998 to a projected 1,100 units in 2006. In contrast, during the same period Windows NT/2000 (and its successors) are expected to increase from 1,350,000 units to 3,364,000 units and Solaris from 142,000 to 470,000. By 2006, OpenVMS will account for less that 2.5% of Intel Itanium-based server sales

Industry Consultants: In March 2002, prior to the Hewlett Packard/Compaq merger, the Gartner Group allocated a “strong negative” rating to the OpenVMS operating system. However, the merger affirmed Compaq’s commitment to porting OpenVMS to Itanium by 2004 and as a result, Gartner revised its overall rating to “caution”. The negative rating still applies to any new business solutions. Giga, another leading IT consulting firm, presents a more optimistic view of the future of OpenVMS. The potential immense backlash from existing OpenVMS customers may be enough for Hewlett Packard not to discontinue marketing and supporting the operating system. IT trade journals presented few articles focused on OpenVMS (except those in OpenVMS journals). Unlike Windows and UNIX, there is a lack of coverage and hype/excitement about OpenVMS.

Independent Software Vendors (ISVs): Despite the commitment from Oracle to continue deploying its products on OpenVMS, Oracle has relegated the OpenVMS operating system to a Tier 2 status platform for its database. As a result, OpenVMS customers can expect to have a longer wait than other customers for updates and software fixes. Cognos has declared that OpenVMS is a Tier 1 operating system for Powerhouse. Despite the 100 ISVs proclaiming support for OpenVMS on Itanium, ISVs may not follow Hewlett Packard’s lead and instead opt to concentrate on developing their applications on more Open-Standards based operating systems or on OS’s with a higher percentage of market share. The prime mission critical application currently located on the OpenVMS servers at Newfoundland Power is the Customer Support Service (CSS) application. Through interviews and documentation, **xwave** found that major CSS and CIS providers were supporting Windows NT/2000 and UNIX platforms as application servers. Those who are supporting OpenVMS tend to use the platform as a database server only.

xwave Internal Research: An investigation of **xwave** sales activity within Atlantic Canada has shown that in August 2002, **xwave** received a request to provide four OpenVMS workstations/servers for a local customer. These computers will be deployed in South America as part of a niche offshore oil application. Prior to this order, the last OpenVMS server sales occurred in January 2001. In contrast, the Sales teams within Atlantic Canada alone have sold hundreds of Intel and UNIX based solutions in the last 18 months. **xwave's** clients often require the services of our IT professionals in order to build or support IT solutions, and to provide consulting services. Throughout 2001 and up to the first half of 2002 there were 154 Windows NT/2000 resource requests issued to the Resource Coordination group. This number contrasts sharply with the two requests issued for OpenVMS resources. One request was from Newfoundland Power, while the other was from a client in Ontario. Each year, **xwave** receives thousands of resumes from IT professionals. Of the 3000 resumes online, only seven indicated that they had any OpenVMS (or VMS) experience. This is in sharp contrast to the nearly 2200 claiming to have some Windows NT experience. Most of the customers who had OpenVMS applications have had them in place for at least 5 – 10 years. Many of these systems were upgrades from older VAX/VMS applications. Customers who were looking to replace the applications on the OpenVMS based servers were considering migrating to other operating systems such Windows 2000, HP-UX, or Solaris if the newer applications were available on these platforms. While most customers were pleased with the level of availability and reliability of their OpenVMS systems, OpenVMS was not seen as a strategic operating system for deploying new mission critical applications.

Education/Training Centres: Education centres and training companies offer a wide array of training courses for companies. The most popular, or “hot”, courses reflect what skills are in demand in the IT industry. Currently, the hottest courses are in the Windows, Database, and UNIX categories. Many learning centres are not offering OpenVMS curriculum.

The research indicated that while OpenVMS was viewed as reliable and stable, the combination of a number of significant factors would limit the potential for OpenVMS to become a mainstream operating system in the midrange market. These factors include:

Market Share: Sales revenues and shipments for OpenVMS are diminishing while Windows and UNIX systems are gaining market share.
ISVs View of OpenVMS: Major Independent Software Vendors (ISVs) such as Oracle have begun to relegate OpenVMS to a Tier 2 platform status, resulting in delays in the release of new versions and fixes of ISV software for the OpenVMS operating system.
Vendor Technology Roadmap: Hewlett Packard has committed to sell AlphaServer technology until 2006. It has stated that it will continue beyond that date only if the demand is present.
Product Availability: The AlphaServer 4100s at Newfoundland Power are no longer sold by Hewlett Packard.
Replacement Parts Availability: Replacement components for the AlphaServer technology will become increasingly difficult to obtain.
Support Requirements: It requires one FTE to support the six OpenVMS servers while two FTEs are supporting the approximately 57 Windows servers at Newfoundland Power.

Diversity/Trend away from OpenVMS: Although there are six OpenVMS servers in use at Newfoundland Power, PROD1 and its disaster recovery server VOLANS host the legacy financials system FASBE as well as SRS, SWITCH, and HRIS. A newer financials system has been deployed on a series of Windows 2000 servers. With the migration of the financials away from OpenVMS, there is further erosion in the prevalence of OpenVMS applications.
Access to Training: Training courses for OpenVMS are difficult to obtain without having to travel outside Canada. Due to the low interest generated for OpenVMS training, courses are not regularly scheduled in Canada.
Access to OpenVMS Skills: People with OpenVMS skills are becoming harder to obtain. Graduates from post secondary institutions are entering the job market with little or no OpenVMS experience. Many, however, have had exposure to Windows and UNIX environments.
OpenVMS Alternatives: Due to the delays in development and limited availability, Itanium has yet to gain mainstream acceptance and its prime target will be software development and high technical computing, neither of which is the computing direction for Newfoundland Power.
Alternate Environments: Windows and UNIX platforms have become more accepted by the IT industry. While there is a consensus that OpenVMS is an available and reliable operating system, Windows and UNIX have gained enough momentum to further erode the OpenVMS future.

These factors indicate that OpenVMS's future as an operating system for critical business applications is limited. Despite assurances from Hewlett Packard, continuing to use OpenVMS contains an unacceptable level of uncertainty and risk. **As a result of the analysis of the Project's research, xwave recommends that Newfoundland Power migrate away from the OpenVMS operating system environment and begin deploying its current OpenVMS based applications onto other operating systems.**

The Project also included the creation of a high-level infrastructure architecture to replace the current CSS infrastructure. By the end of 2003, all the applications on the OpenVMS servers except CSS will have been replaced. The two alternative environments presented in Section 5 are based upon Microsoft Windows 2000 and UNIX. These operating systems were chosen as alternatives because Newfoundland Power has experience with both - Windows through the deployment of applications such as the Great Plains application and UNIX through the Tru64 SCADA implementation. It is important to note that the configurations and prices reflect current technology as of August 2002.

The Windows 2000 alternative involves the deployment of two production servers, as well as two additional servers that would accommodate application development and disaster recovery. The following table summarizes the server infrastructure and provides a high-level estimate of hardware and software required to implement this solution.

CSS Windows 2000 Environment		
Environment	Requirements	Cost
Production	One Compaq DL580 database server One Compaq DL380 application server 437 GB external storage One server rack One communications switch	$132,800
Development / Disaster Recovery	One Compaq DL580 database server One Compaq DL380 application server 437 GB external storage One server rack One communications switch	$120,500
	Total (excluding tax)	$253,300.00

The servers would connect to the Storage Area Network (SAN) solution proposed recently by **xwave**. As a result, 874 GB of external disk storage would be installed in the SAN for use by the servers.

The UNIX alternative involved the deployment of two production servers, as well as two servers that would accommodate application development and disaster recovery.

CSS UNIX Environment		
Environment	Requirements	Cost
Production	One Sun Microsystems Sun Fire V480 database server One Sun Microsystems Sun Fire V480 application server One Sun StorEdge D2 Array One server rack One communications switch	$175,300
Development / Disaster Recovery	One Sun Microsystems Sun Fire V480 database server One Sun Microsystems Sun Fire V480 application server One Sun StorEdge D2 Array One server rack One communications switch	$142,600
	Total (excluding tax)	$317,900.00

At this time, **xwave** does not make a recommendation between Windows 2000 and UNIX as the preferred alternative. The final decision on which platform to deploy depends upon the future direction of applications such as the Customer Support System (CSS). Specifically, future replacements for these applications will determine which operating systems should be used and the level of hardware to be deployed.

The remainder of this report details **xwave**'s investigation into OpenVMS as well as an analysis of the information gathered.

2.0 INTRODUCTION

2.1 PURPOSE

Newfoundland Power currently utilizes the OpenVMS environment for some of its corporate applications. OpenVMS has been the primary application development environment for a number of years offering maturity and stability. However, Newfoundland Power is at a critical juncture with respect to selection of a computing platform for much of its core production environment. Its OpenVMS servers are from four to seven years old and are becoming limited in their scalability. Applications such as Great Plains have been implemented in the Windows environment. While much of the decision around future platforms for supporting a 7/24 operational environment will be tied to the selection of the application vendor, this is also a fundamental decision on the horizon that must be addressed.

The primary objective of the OpenVMS Research Project (the Project) was to investigate the prevalence and future direction of OpenVMS environment. These research findings are intended to assist Newfoundland Power in making a decision regarding whether to migrate from the OpenVMS environment. A second objective of the Project was to identify high-level technical architecture options to maintain the current level of stability, reliability and availability.

Information for the Project was gathered from both primary and secondary sources. Interviews and questionnaires were used to gather information from industry consultants, hardware and software vendors, OpenVMS customers and Newfoundland Power staff. Secondary sources included white papers, research opinions and strategy documents..

With any decision to migrate from OpenVMS to another platform, it is necessary to ensure that the associated level of processes, security, reliability, manageability and scalability exists. It is also important to promote an “open” computing environment that will allow various platforms (NT, 2000, UNIX, etc.) to share technology. The adoption of “open” technology will ensure any solution/application selected will address business needs and determine the technology platform. This is important to ensure solutions are business driven and not technology driven.

The Windows/Intel Platform is the other major application environment at Newfoundland Power. Driven by office productivity tools, email and smaller applications this platform already plays an important role in the delivery of IT services and solutions. Currently, the growth of the WinTel environment is based on a single server–single application or multiple server–single application model. The results have been an increase in the physical number of servers and associated cost, labour, maintenance and monitoring required.

2.2 SCOPE

The scope of the Project was limited to Newfoundland Power's OpenVMS infrastructure located at the Kenmount Road and Pippy Place offices in St. John's, Newfoundland.

In order to complete the investigation, a number of specific areas of investigation were undertaken. The scope of investigation included the following:

- Reviewing Newfoundland Power's current position on migrating away from OpenVMS;
- Reviewing the current OpenVMS infrastructure including core business applications and supporting infrastructure;
- Reviewing pertinent business application options with respect to OpenVMS, including identifying application manufacturer's preferred platform, configuration, and supporting infrastructure (email, Database Management System (DBMS), Storage);
- Reviewing alternative platform options (Operating Systems & Hardware) with respect to OpenVMS, including a comparative review of Newfoundland Power's preferred solution;
- Reviewing project summaries of active or planned projects that are deemed by Newfoundland Power to have an impact or be impacted by a migration away from OpenVMS;
- Reviewing primary business drivers that influence business application directions;
- Reviewing supportability of the OpenVMS platform including such key points as skill set, availability and installation base; and,
- Creating a high-level infrastructure architecture to replace the current OpenVMS based infrastructure.

2.3 ASSUMPTIONS

In order to ensure the Project was completed in the time allowed, **xwave** made some key assumptions, which were:

- Newfoundland Power was earnest in considering a migration away from OpenVMS as part of their IT strategy.
- The required resources would be made available on the mutually agreed upon times.
- Infrastructure diagrams (in electronic format) would be made available to **xwave** prior to commencement of the engagement.
- All existing planning documentation (Return on Investment / Total Cost of Ownership Studies, Strategic Plans, and Road Maps) would be made available to **xwave** prior to commencement of the engagement.
- A system inventory of the pertinent systems existed and an electronic copy would be made available to **xwave**.

3.0 RESEARCH ACTIVITIES

3.1 PRIMARY AND SECONDARY SOURCES

In order to facilitate the successful completion of this research project, a series of meetings and interviews were held which consisted of a combination of primary and secondary sources.

Primary sources were a series of technical interviews and questionnaires. Secondary sources consisted of the collection of technical white papers, research opinions, strategy documents and technology roadmaps.

xwave gathered information from four opinion groups while conducting the research. These included:

- Newfoundland Power
- **xwave**
- Vendors
- Industry Consultants

3.2 NEWFOUNDLAND POWER

A technical questionnaire was developed and provided to Newfoundland Power. The questionnaire focused on the OpenVMS computing environment at Newfoundland Power. The questions involved:

- OpenVMS server configurations
- Age of the servers
- Business functions and applications on each server
- Software located on each servers
- Server locations
- Resourcing required to support the OpenVMS environment
- Vendor support agreements
- Levels of availability expected by the user community
- External interfaces
- The user community
- Hardware and software licensing

The questionnaire and the responses can be found in Appendix A.

Keith Lefeuvre, an Infrastructure Analyst, was assigned to complete the questionnaire. Once completed, the questionnaire was returned to **xwave** for investigation. The responses to the initial questionnaire generated a number of follow-up and clarification questions.

The completed questionnaire was input to an interview session between **xwave** and Mr. Lefeuvre. The aim of the interview was to obtain a better understanding of the role of the OpenVMS technology in Newfoundland Power. While acting as a clarification session for the questionnaire, the interview also produced information on the processes surrounding the OpenVMS servers. These processes include:

- File and system backup
- Batch processing
- Change management
- Disaster recovery

In addition to the questionnaire and the technical interview, there were a series of correspondences between **xwave** and Mr. Lefeuvre. These correspondences also provided valuable information on the OpenVMS environment at Newfoundland Power.

Mr. Lefeuvre also provided the document *Obsolescence and the OpenVMS Operating System: An Emerging Technology Issue at Newfoundland Power,* dated August 2001. The document discussed the implications associated with remaining on, and migrating away from, the OpenVMS environment.

3.3 XWAVE

Interviews were held with people in various departments within **xwave**. These included:

- Sales teams
- Resource coordinators
- Technology consultants
- Server support resources
- Trainers
- Recruiters

The focus of these interviews was to gain an appreciation of the demand for OpenVMS from clients and within the IT industry. **xwave** has over 2590 employees in centres across North America and in Europe. In addition to the interviews, **xwave** has developed a repository of technical information, technology roadmaps, and best practices.

This extensive knowledge base enabled **xwave** to provide valuable insight into the demands and the trends within the Information Technology industry.

3.4 VENDORS

Interviews were held with key software vendors that were identified as those vendors whose products directly affected the OpenVMS environment at Newfoundland Power. The interviews centred on the level at which they considered OpenVMS to be a strategic platform. The vendors also provided technology roadmaps for their products, detailing the relationship of their software to OpenVMS.

Vendors were categorized as either application providers or software toolset vendors. An example of an application provider would be Microsoft (Great Plains). Oracle Corporation would be considered a toolset vendor.

3.5 INDUSTRY

An important indicator of the prevalence of OpenVMS can be obtained by gathering information from various industries. **xwave** has customers in most major industries. **xwave** used the relationship it has with these customers to gather information on the prevalence of OpenVMS within these organizations and whether or not OpenVMS is part of their strategic IT plans.

Through a series of customer and account manager interviews, **xwave** was able to develop some insight into our clients' views on OpenVMS.

4.0 RESEARCH FINDINGS

This section presents the findings of the primary and secondary research completed by **xwave**. Detailed findings are outlined in Sections 4.2 through 4.9 and supporting appendices. Section 4.1 presents a summary of research findings.

4.1 SUMMARY OF RESEARCH FINDINGS

OpenVMS Environment

- Various generations of OpenVMS have been available since 1977.
- There are over 30 OpenVMS customers in Atlantic Canada.

OpenVMS at Newfoundland Power

- Newfoundland Power has six OpenVMS servers ranging in age from three years to seven. The AlphaServer 4100 server line has been discontinued and spare parts have to be purchased from third party vendors.
- One Full Time Equivalent (FTE) is required to support the six OpenVMS servers compared to two FTEs to support the Intel environment consisting of 57 Compaq servers. While it is not always appropriate to assume a one-to-one relationship between OpenVMS and Windows server support, total server support effort would likely be reduced by migrating from OpenVMS to Windows or UNIX.
- Newfoundland Power's current plan is to replace all the applications on the OpenVMS servers except CSS by December 2003.
- The OpenVMS platforms provide a highly stable, reliable and available environment for the applications residing on them. However, they require a significant level of manual care and intervention that adds to the resource requirements for the servers.

OpenVMS Roadmaps

- Hewlett Packard has stated that OpenVMS will be sold on the AlphaServer technology until at least 2006, and will be supported on this platform until at least 2011.
- The AlphaServer will be marketed at least until 2006 and supported for an additional 5 years.
- Hewlett Packard will release a production version of OpenVMS on the Itanium technology around 2004-2005.

OpenVMS Revenues and Shipments

- By 2006, revenues from new sales of OpenVMS are expected to decline to $36 Million from $806 Million in 1998. During the same period Windows NT/2000 will rise to $16.3 Billion from $6.9 Billion and Solaris to $9.9 Billion from $4.9 Billion.
- OpenVMS shipments are projected to decrease from 19,000 units in 1998 to a projected 1,100 units in 2006. In contrast, during the same period Windows NT/2000 (and its successors) are expected to increase from 1,350,000 units to 3,364,000 units and Solaris from 142,000 to 470,000.
- By 2006, OpenVMS will account for less that 2.5% of Itanium sales.

Industry Consultants

- In March 2002, prior to the Hewlett Packard/Compaq merger, the Gartner Group allocated a “strong negative” rating to the OpenVMS operating system. However, the merger affirmed Compaq’s commitment to porting OpenVMS to Itanium by 2004 and as a result, Gartner revised its overall rating to “caution”. The negative rating still applies to any new business solutions.
- Giga presents a more optimistic view of the future of OpenVMS. The potential immense backlash from existing OpenVMS customers may be enough for Hewlett Packard not to discontinue marketing and supporting the operating system.
- While researching the prevalence on OpenVMS, IT trade journals were investigated. Few articles focused on OpenVMS except those in OpenVMS journals. Unlike Windows and UNIX, there is a lack of coverage and hype/excitement about OpenVMS.

Independent Software Vendors (ISVs)

- Despite the commitment from Oracle to continue deploying its products on OpenVMS, Oracle has relegated the OpenVMS operating system to a Tier 2 status platform for its database. As a result, OpenVMS customers can expect to have to wait longer than other customers to receive updates and software fixes.
- Cognos has declared that OpenVMS is a Tier 1 operating system for Powerhouse.
- Despite the 100 ISVs proclaiming support for OpenVMS on Itanium, ISVs may not follow Hewlett Packard’s lead and instead opt to concentrate on developing their applications on more Open-Standards based operating systems or on OS’s with a higher percentage of market share.
- The prime mission critical application currently located on the OpenVMS servers at Newfoundland Power is the Customer Support Service (CSS) application. Through interviews and documentation, **xwave** found that major CSS and CIS providers were supporting Windows NT/2000 and UNIX platforms as application servers.

xwave Internal Research

- An investigation of **xwave** sales activity within Atlantic Canada has shown that in August 2002, xwave received a request to provide four OpenVMS workstations/servers for a local customer. These computers will be deployed in South America as part of a niche offshore oil application. Prior to this order, the last OpenVMS server sales occurred in January 2001. In contrast, the Sales teams within Atlantic Canada alone have sold hundreds of Intel and UNIX based solutions in the last 18 months.
- **xwave**’s clients often require the services of our IT professionals in order to build or support IT solutions, and to provide consulting services. Throughout 2001 and up to the first half of 2002 there were 154 Windows NT/2000 resource requests issued to the Resource Coordination group. This number contrasts sharply with the two requests issued for OpenVMS resources.
- Every year **xwave** receives thousands of resumes from IT professionals. Of the 3000 resumes online, only seven indicated that they had any OpenVMS (or VMS) experience. This is in sharp contrast to the nearly 2200 claiming to have some Windows NT experience.

- Most of the customers who had OpenVMS applications have had them in place for at least 5 – 10 years. Many of these systems were upgrades from older VAX/VMS applications. Customers who were looking to replace the applications on the OpenVMS based servers were considering migrating to other operating systems such Windows 2000, HP-UX, or Solaris if the newer applications were available on these platforms. While most customers were pleased with the level of availability and reliability of their OpenVMS systems, OpenVMS was not seen as a strategic operating system for deploying new mission critical applications.

Education/Training Centres

- Education centres and training companies offer a wide array of training courses for companies. The most popular, or "hot", courses reflect what skills are in demand in the IT industry. Currently, the hottest courses are in the Windows, Database, and UNIX categories. Many learning centres are not offering OpenVMS curriculum.

The following sections provide more detail to the findings summarized above.

4.2 OPENVMS ENVIRONMENT

4.2.1 OpenVMS

OpenVMS, originally called VMS (Virtual Memory System), was first conceived in 1976 as a new operating system for the then-new, 32-bit, virtual memory line of computers, eventually named VAX (Virtual Address eXtension).

The first VAX model, the 11/780, was code-named ‘‘Star’’, hence the code name for the VMS operating system, ‘‘Starlet’’, a name that remains to this day the name for the system library files (STARLET.OLB, etc.).

VMS version X0.5 was the first released to customers, in support of the hardware beta test of the VAX-11/780, in 1977. VAX/VMS Version V1.0 shipped in 1978, along with the first revenue-ship 11/780s.

OpenVMS was designed entirely within Hewlett Packard and specifically within the former Digital Equipment Corporation (DIGITAL). Two of the principal designers were Dave Cutler (the Architect of Microsoft's Windows NT) and Dick Hustvedt, though with a wide variety of other contributors. OpenVMS was conceived as a 32-bit, virtual memory successor to the RSX-11M operating system for the PDP-11. Many of the original designers and programmers of OpenVMS had worked previously on RSX-11M, and many concepts from RSX-11M were carried over to OpenVMS.

OpenVMS VAX is a 32-bit, multitasking, multiprocessing virtual memory operating system. Current implementations run on VAX systems from Hewlett Packard and other vendors.

OpenVMS Alpha is a 64-bit multitasking, multiprocessing virtual memory operating system. Current implementations run on Alpha systems from Hewlett Packard, and other vendors.

Work to port OpenVMS to systems based on the Intel IA-64 architecture and specifically to the Itanium Processor Family is presently underway.

Itanium is Intel's newest microprocessor based on 64-bit architecture. The 64-bit design provides access to very large memory, in effect allowing a 64-bit application to access memory in excess of 4 gigabytes in size. With databases becoming larger and having a more important role in applications, many of software and hardware vendors are in the process of developing systems and applications for the Itanium.

Hewlett Packard states that the OpenVMS operating system is deployed on over 400,000 servers today, although industry analysts believe that this number may be comprised of the following types of systems:

1. Online production and development OpenVMS systems;
2. Older VAX/VMS systems;
3. Offline, or not in use, OpenVMS systems.

Although unwilling to provide exact numbers or names of customers in Atlantic Canada, Hewlett Packard has stated that they have over 30 OpenVMS customers in the region. These customers include private companies, government departments, post secondary institutions, and utility companies.

In April 2002, Hewlett Packard and Compaq announced that the two companies have merged into a single organization. As a result, there were impacts on technologies that had been previously marketed by the individual companies. Products such as the AlphaServer line and OpenVMS from Compaq and Itanium development by Hewlett Packard are within the scope of this investigation. Other products such as the UNIX operating systems – Hewlett Packard's HP-UX and Compaq's Tru64, fall outside the scope of this research. However, it is important to note that the current plan for Tru64 is to migrate its functionality into future releases of HP-UX, eventually discontinuing the Tru64 operating system in favour of HP-UX. This action impacts Newfoundland Power because the software that runs its SCADA network is based upon Tru64. Newfoundland Power will have to consider the migration of its SCADA software prior to the removal of Tru64 from Hewlett Packard's product line.

4.2.2 Current OpenVMS Environment at Newfoundland Power

The current OpenVMS environment at Newfoundland Power consists of six Compaq AlphaServers. The tables below detail the server configurations as well as the applications and software located on the servers.

Server	Compaq Model	CPU (MHz)	Memory (GB)	Disk Storage (GB)	Purchase Date
DRACO	AlphaServer 4100	2 X 533	6	226	1998
PROD1	AlphaServer 4100	2 X 466	2	110	1998
ORION	AlphaServer 4100	2 X 300	1	125	1997
CORVUS	AlphaServer 4100	2 X 533	4	226	1998
VOLANS	AlphaServer 4100	2 X 466	2	110	1999
CYGNUS	AlphaServer 2100	2 X 250	1.28	130	1995

Table 1 – OpenVMS Servers at Newfoundland Power

OpenVMS Applications at Newfoundland Power	
Server	**Application**
DRACO	Customer Support System (CSS) Problem Call Logging System (PCLS/Interruptions) Joint Use System (JUS) Street Light Management System (SLMS) MES
PROD1	Spill Reporting System (SRS) SWITCH FASBE HRIS PES TLIS
ORION	Development for all applications on DRACO and PROD1
CORVUS	Disaster Recovery for DRACO
VOLANS	Disaster Recovery for PROD1
CYGNUS	Disaster Recovery for ORION

Table 2 – OpenVMS Applications at Newfoundland Power

OpenVMS Software at Newfoundland Power						
Software	**DRACO**	**PROD1**	**ORION**	**CORVUS**	**VOLANS**	**CYGNUS**
COBOL Developer			X			X
Cobol Runtime	X	X	X	X	X	X
BASIC Developer			X			X
BASIC Runtime	X	X	X	X	X	X
FORTRAN Developer			X			X
FORTRAN Runtime	X	X	X	X	X	X
Oracle Enterprise	X	X	X	X	X	X
DECnet	X	X	X	X	X	X
DECEvent	X	X	X	X	X	X
DECForms Developer			X			X
DECForms Runtime	X			X		
DECWindows	X	X	X	X	X	X
AdviseIT	X	X	X	X	X	X
TCPWare	X	X	X	X	X	X
PVCS			X			X
Cognos Powerhouse	X	X	X	X	X	X
Wordperfect	X			X		

Table 3 – OpenVMS Software at Newfoundland Power

The Customer Support System is the most mission critical application in the OpenVMS environment at Newfoundland Power. The application must be available between 8 AM and 8 PM Monday to Friday for the front line CSS users.

There is a maximum outage of .5 hour allowed during the prime shift except in rare emergencies. Scheduled outages can be longer on the weekends. Environmental considerations such as inclement weather or problems with the electrical grid will impact planned outages.

DRACO and PROD1 are production servers. ORION houses the development efforts for the applications on DRACO and PROD1 and is also considered a production environment in the sense that a failure in ORION results in developers becoming unable to work.

The three remaining servers – CORVUS, VOLANS, and CYGNUS are disaster recovery servers for the three production servers. In the event of a failure in one of the production servers, the nightly backup from the previous night is used to recover the applications onto the corresponding disaster recovery server.

The servers are backed up using a DLT tape drive and the tapes are taken off site to the server’s disaster recovery site. Full backups are performed once per week and incremental backup on the other four days. Backups are coordinated and initiated by the Computer Room operators.

Due to the high level of availability required for the production servers, they have 24 X 7 hardware and software maintenance agreements with the vendors. These agreements include a 2-hour callback for problem determination and a 4-hour delivery of replacement parts.

The disaster recovery servers have 9 X 5 hardware and software maintenance agreements.

Hewlett Packard OpenView and in-house developed scripts are used to alert support staff of problems with the servers.

DRACO, PROD1, ORION, and CYGNUS are located at the Kenmount Road datacentre. CORVUS and VOLANS are at Duffy Place.

One Full Time Equivalent (FTE) is required to support the six OpenVMS servers. This role is divided between two resources, Keith Lefeuvre and Sean Kearley. As a comparison of the effort to maintain this environment, the Intel environment at Newfoundland Power consists of 57 Compaq servers. Support for this infrastructure requires two FTEs. It is important to note that it is not always appropriate to assume a one-to-one relationship between OpenVMS and Windows server support. A single OpenVMS server may be able to accommodate a number of applications, as is the case with the Newfoundland Power servers, while the same applications ported to a Windows environment may require multiple servers. However, the magnitude of the difference between the support requirements for the OpenVMS and the Windows environments is large enough that overall support requirements can be reduced by migrating the OpenVMS applications to the Windows or UNIX environments.

The OpenVMS platforms provide a highly stable, reliable and available environment for the applications residing on them. However, they require a significant level of manual care and intervention. Batch job processing at night is a manual process in which the computer room operator releases each batch job, reviews the output for errors, and makes the decision whether to continue with the successive job.

Newfoundland Power's current plan is to replace all the applications on the OpenVMS servers except CSS within the next 18 months. FASBE and HRIS will be replaced by June 2003 and the remaining eight applications by December 2003.

Newfoundland Power has been considering a migration away from the OpenVMS environment. In August 2001, a white paper entitled *Obsolescence and the OpenVMS Operating System: An Emerging Technology Issue at Newfoundland Power* was created. The document discussed the advantages and disadvantages of migrating away from OpenVMS. While not explicitly stating that Newfoundland Power is abandoning the operating system, the following excerpt reveals Newfoundland Power's concern with the future of OpenVMS:

"Independent software vendor support for the OpenVMS operating system is in decline. Newfoundland Power has experienced several examples of the impact of this issue, and is responding accordingly. The Company anticipates this issue will continue to emerge in the near term and has initiated plans to mitigate the risks, thereby minimizing any negative impact on customer service and operating efficiencies.

Moving forward, Newfoundland Power will continue to monitor IT industry developments, especially with respect to OpenVMS, and adjust its plans accordingly."

Obsolescence and the OpenVMS Operating System:
An Emerging Technology Issue at Newfoundland Power
August 2001, Newfoundland Power

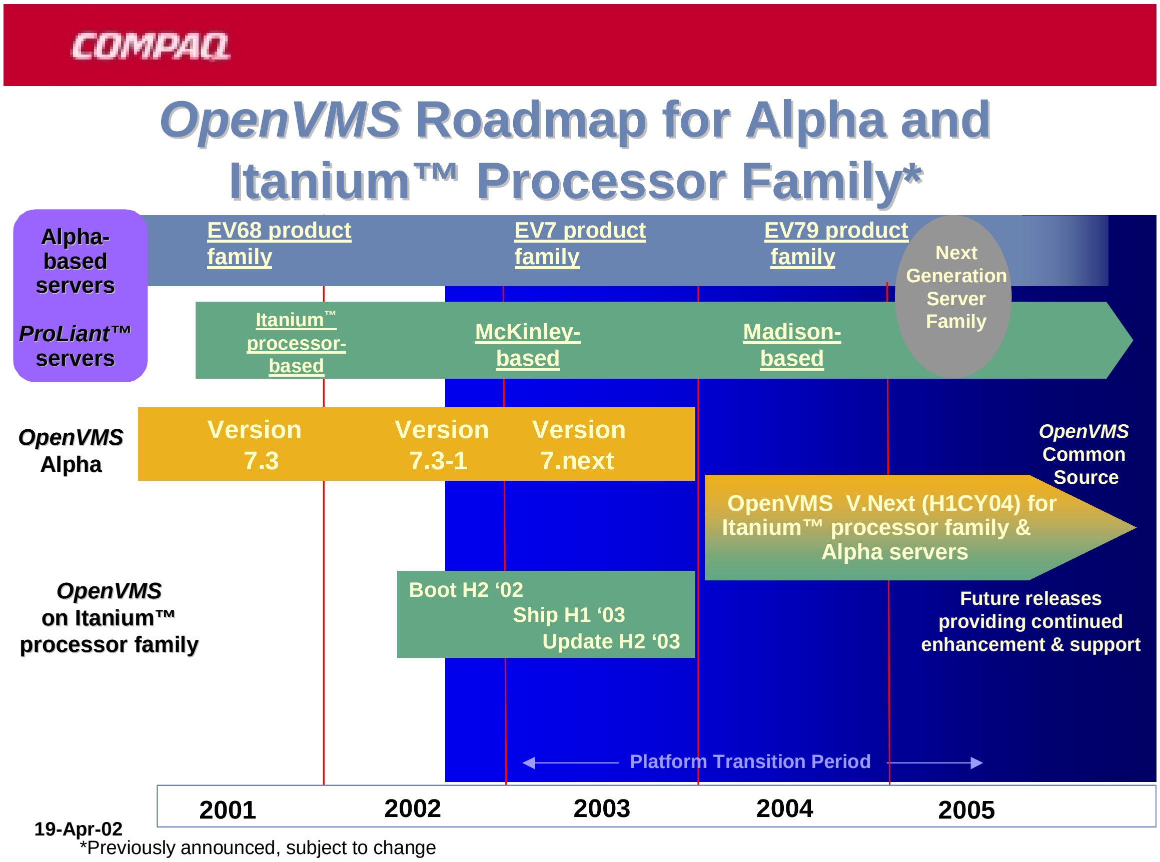
4.3 OPENVMS ROADMAPS

The roadmaps for OpenVMS over the next 4 years follow both the AlphaServer and the Itanium processors.

4.3.1 AlphaServer and Itanium Roadmap

Hewlett Packard plans to continue to release new processor functionality on the upcoming EV7 and EV79-based AlphaServer systems, and intends to sell the AlphaServer line until at least 2006, with support through to at least 2011. Hewlett Packard already has Itanium based servers available and will develop new generations of the Itanium chip in the future.

The diagram below details the AlphaServer and the Itanium Roadmap. Following the Hewlett Packard – Compaq merger, Hewlett Packard publicly stated that the current roadmaps for AlphaServer and Itanium are still valid, it has reserved the right to subject the roadmaps to change.



COMPAQ

OpenVMS Roadmap for Alpha and Itanium™ Processor Family*

Alpha-based servers

ProLiant™ servers

EV68 product family

EV7 product family

EV79 product family

Next Generation Server Family

Itanium™ processor-based

McKinley-based

Madison-based

OpenVMS Alpha

Version 7.3

Version 7.3-1

Version 7.next

OpenVMS Common Source

OpenVMS V.Next (H1CY04) for Itanium™ processor family & Alpha servers

OpenVMS on Itanium™ processor family

Boot H2 '02

Ship H1 '03

Update H2 '03

Future releases providing continued enhancement & support

Platform Transition Period

2001 2002 2003 2004 2005

19-Apr-02

*Previously announced, subject to change

Courtesy of Hewlett Packard

Table 4 – Alpha and Itanium Roadmap

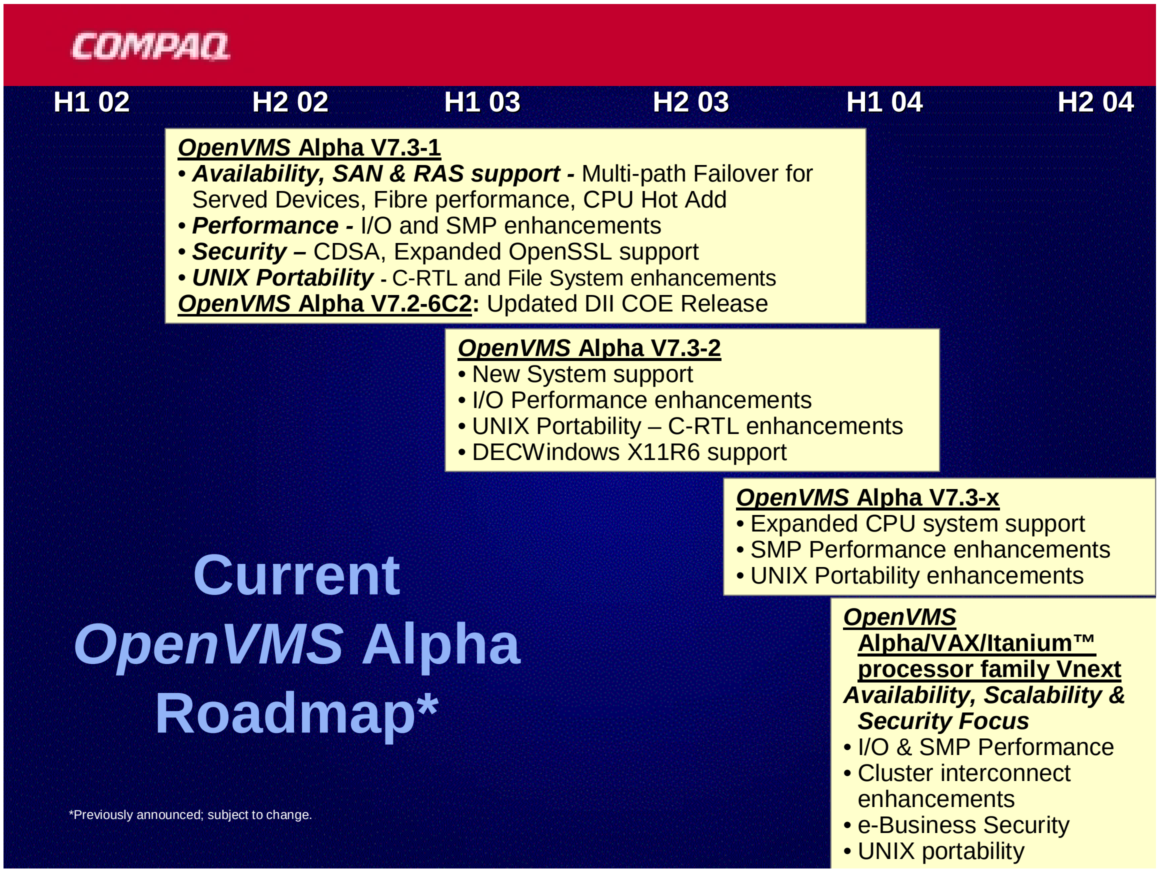
4.3.2 OpenVMS on Alpha Roadmap

Hewlett Packard also plans to continue to release new OpenVMS functionality on the upcoming EV7 and EV79-based AlphaServer systems. Sales of OpenVMS on the AlphaServer will continue until at least 2006, with support through to at least 2011. The table below indicates the versions of OpenVMS that will be supported on each generation of the AlphaServer processor.

AlphaServer Generation	Release Date	OpenVMS Version Supported
EV68	Available	7.3
EV 7	2003	7.3-1
EV79	2004	7.X

Table 5 – OpenVMS Versions on Alpha

The OpenVMS systems at Newfoundland Power are currently at version 7.2-1. The diagram below details the current OpenVMS Roadmap for AlphaServer.



COMPAQ

H1 02 H2 02 H1 03 H2 03 H1 04 H2 04

***OpenVMS* Alpha V7.3-1**
- ***Availability, SAN & RAS support -*** Multi-path Failover for Served Devices, Fibre performance, CPU Hot Add
- ***Performance -*** I/O and SMP enhancements
- ***Security –*** CDSA, Expanded OpenSSL support
- ***UNIX Portability*** - C-RTL and File System enhancements

***OpenVMS* Alpha V7.2-6C2:** Updated DII COE Release

***OpenVMS* Alpha V7.3-2**
- New System support
- I/O Performance enhancements
- UNIX Portability – C-RTL enhancements
- DECWindows X11R6 support

***OpenVMS* Alpha V7.3-x**
- Expanded CPU system support
- SMP Performance enhancements
- UNIX Portability enhancements

***OpenVMS* Alpha/VAX/Itanium™ processor family Vnext**

Availability, Scalability & Security Focus
- I/O & SMP Performance
- Cluster interconnect enhancements
- e-Business Security
- UNIX portability

Current *OpenVMS* Alpha Roadmap*

*Previously announced; subject to change.

Courtesy of Hewlett Packard

Table 6 – OpenVMS on Alpha Roadmap

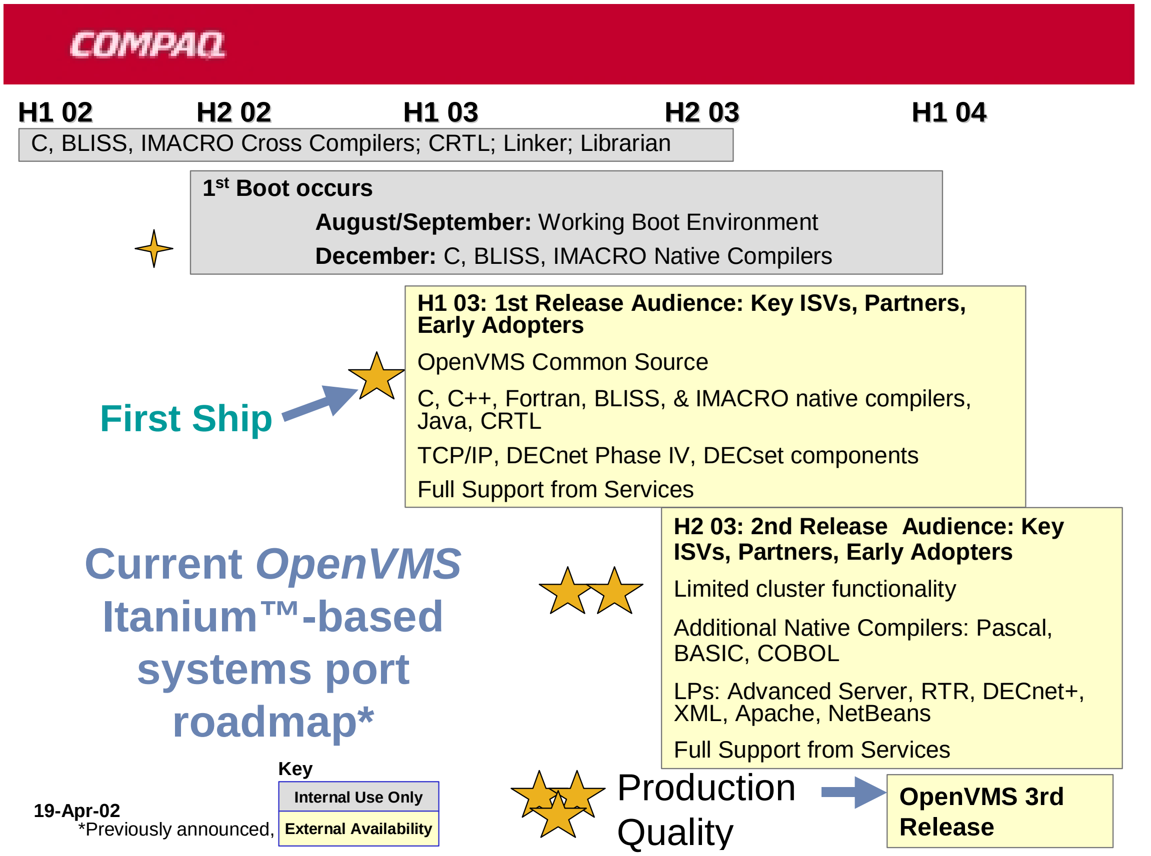
4.3.3 OpenVMS on Itanium Roadmap

On June 25 2001, Compaq announced that its OpenVMS operating system would be ported to Itanium architecture. Development would start in 2002 with a full release of the operating system in 2004.

The porting would be a gradual process, with multiple releases during the 2.5-year schedule. Each succeeding release would provide more functionality until a “Production Quality” release became available to customers in 2004.

After the Hewlett Packard/Compaq merger, Hewlett Packard reaffirmed the previously announced roadmap for OpenVMS on Itanium.

The diagram below details the rollout schedule for the various components of OpenVMS on Itanium.



H1 02 H2 02 H1 03 H2 03 H1 04

C, BLISS, IMACRO Cross Compilers; CRTL; Linker; Librarian

1st Boot occurs

August/September: Working Boot Environment

December: C, BLISS, IMACRO Native Compilers

H1 03: 1st Release Audience: Key ISVs, Partners, Early Adopters

OpenVMS Common Source

C, C++, Fortran, BLISS, & IMACRO native compilers, Java, CRTL

TCP/IP, DECnet Phase IV, DECset components

Full Support from Services

First Ship

H2 03: 2nd Release Audience: Key ISVs, Partners, Early Adopters

Limited cluster functionality

Additional Native Compilers: Pascal, BASIC, COBOL

LPs: Advanced Server, RTR, DECnet+, XML, Apache, NetBeans

Full Support from Services

Current *OpenVMS* Itanium™-based systems port roadmap*

Key

Internal Use Only

External Availability

19-Apr-02

*Previously announced,

Production Quality

OpenVMS 3rd Release

Courtesy of Hewlett Packard

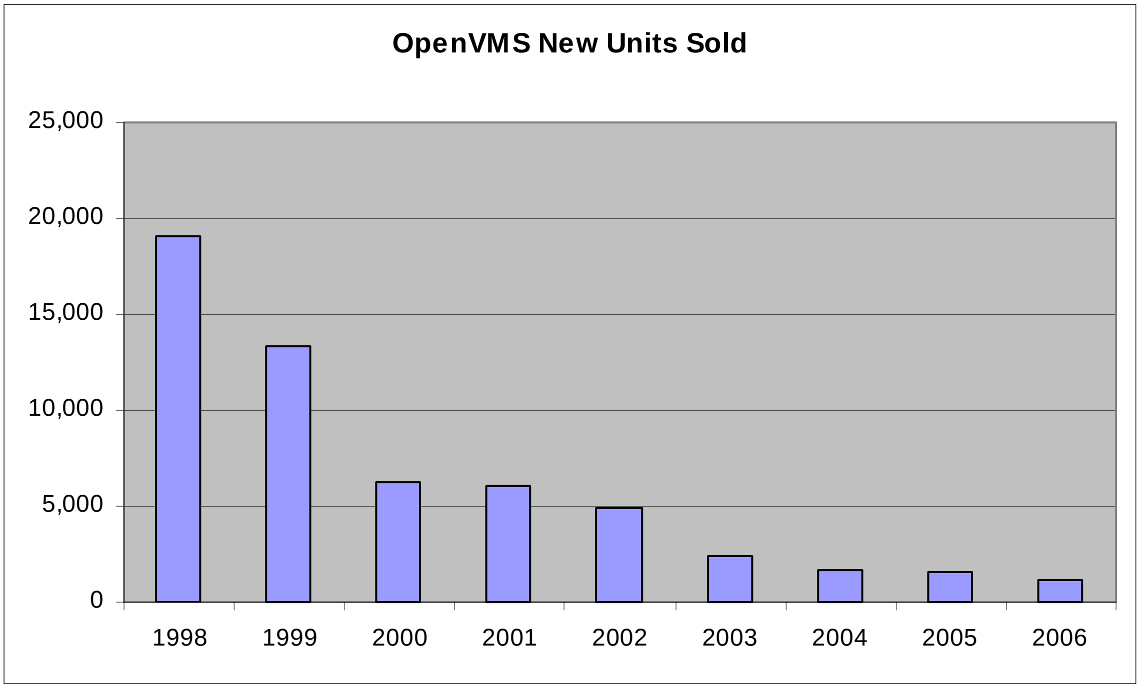
Table 7 – OpenVMS on Itanium Roadmap

Hewlett Packard indicates that there is excitement among its ISVs over the porting of OpenVMS to the Itanium Processor family platform. Testimonials from more than 100 partners indicating their intent to continue to support OpenVMS can be found on the Hewlett Packard website.

4.4 OPENVMS REVENUES AND SHIPMENTS

OpenVMS has seen a decline in the numbers of units shipped as well as the revenue for new units sold. Industry analysts predict that this trend will continue, reducing OpenVMS's share of the marketplace for midrange operating systems.

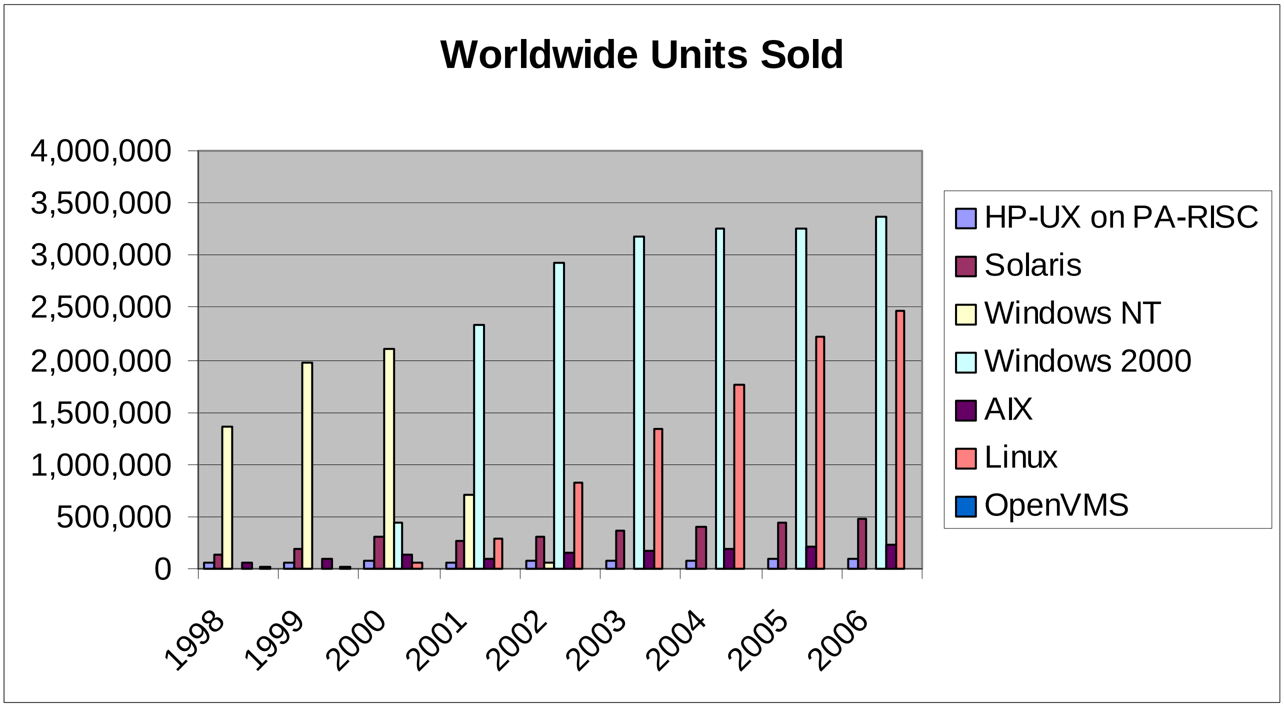
The chart below details the number of OpenVMS operating systems shipped since 1998 and makes projections out to 2006.



Courtesy of Gartner/Sun Microsystems

Table 8 – OpenVMS Units Sold from 1998 - 2006

OpenVMS is expected to go from 19,000 units shipped in 1998 down to 1,100 units in 2006. OpenVMS's diminishing impact on the marketplace for operating systems is underscored when the number of OpenVMS units shipped is compared to other operating systems. The chart below shows the number of midrange and Windows operating systems shipped since 1998 and makes projections out to 2006.



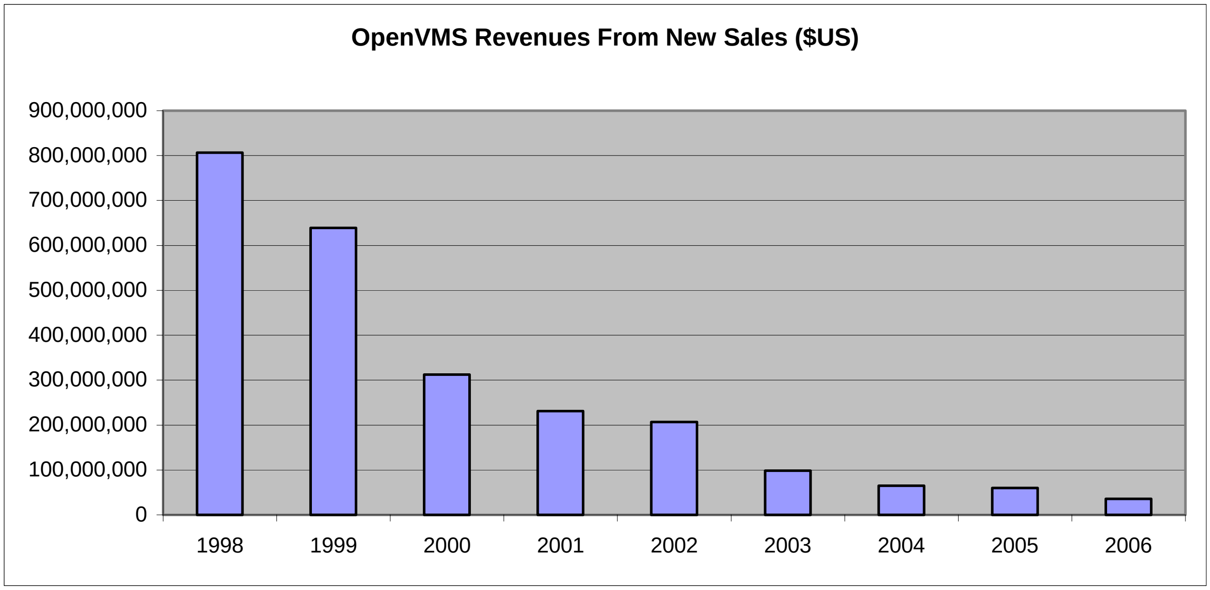
Courtesy of Gartner/SunMicrosystems

Table 9 – Worldwide Sales of Operating Systems from 1998 - 2006

Windows 2000 (and its successors) and Linux will become the primary operating systems sold. Revenues from sales of new OpenVMS operating systems sold will also decline from 1998 to 2006. The values for the table above are presented below.

Worldwide Units Sold									
	1998	1999	2000	2001	2002	2003	2004	2005	2006
HP-UX	60901	59903	71688	60368	70412	71473	79101	87827	102120
Solaris	142101	185278	302669	269362	314297	360446	400152	433564	469765
Windows NT	1349998	1967625	2103545	706758	56618	0	0	0	0
Windows 2000	0	0	440040	2326538	2933265	3180907	3259185	3261783	3363964
AIX	62866	92547	126619	96636	149386	173465	196967	213413	228956
Linux	0	1738	56855	284718	827499	1346337	1766165	2221630	2470505
OpenVMS	19103	13370	6245	6013	4864	2365	1718	1581	1135

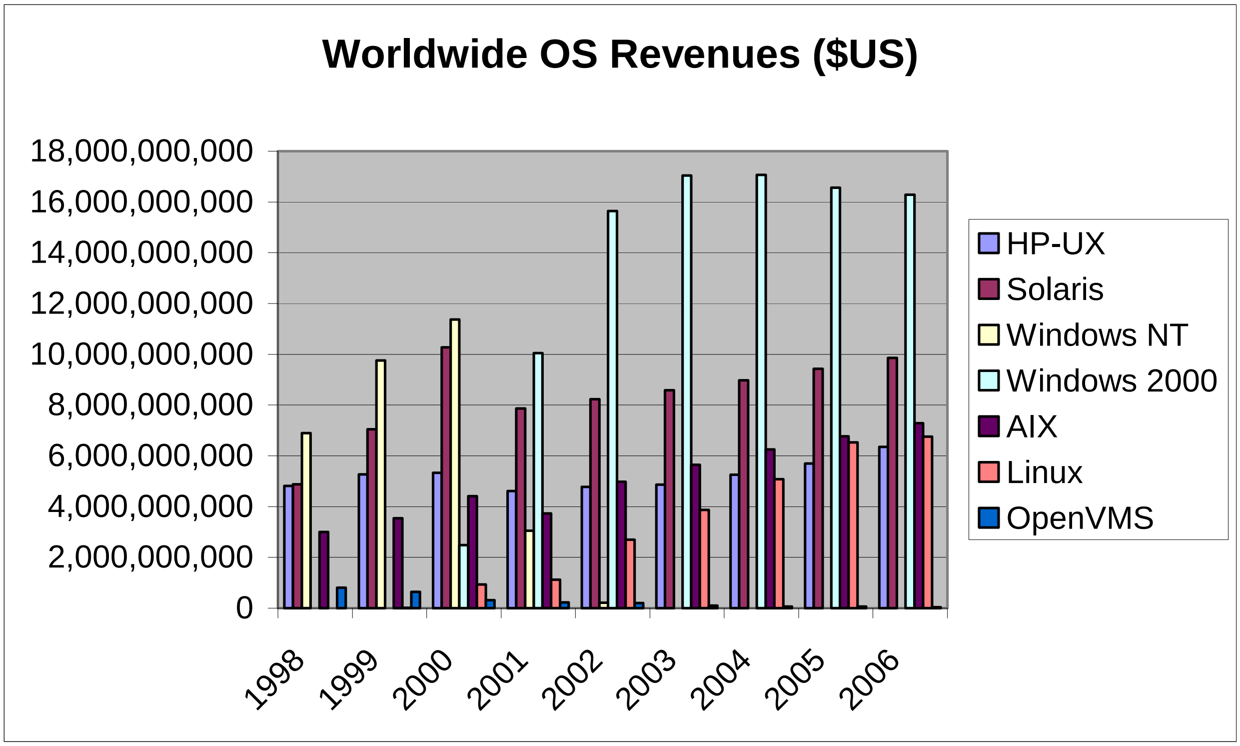
Courtesy of Gartner/SunMicrosystems



Courtesy of Gartner/Sun Microsystems

Table 10 – OpenVMS Revenues on New Sales from 1998 - 2006

In terms of revenues from the sale of operating systems, Windows 2000 (and its successors) and Linux will again lead the industry.



Courtesy of Gartner/Sun Microsystems

Table 11 – Worldwide Operating System Revenues on New Sales from 1998 - 2006

The values for the table above are presented below.

Worldwide OS Revenues ($US Billion)									
	1998	1999	2000	2001	2002	2003	2004	2005	2006
HP-UX	4.81	5.26	5.33	4.61	4.78	4.86	5.26	5.70	6.36
Solaris	4.88	7.05	10.27	7.87	8.24	8.59	8.98	9.43	9.86
Windows NT	6.89	9.76	11.38	3.05	0.22	0.00	0.00	0.00	0.00
Windows 2000	0.00	0.00	2.48	10.04	15.64	17.04	17.06	16.57	16.29
AIX	3.00	3.54	4.41	3.73	4.98	5.64	6.25	6.77	7.29
Linux	0.00	0.01	0.93	1.12	2.70	3.88	5.08	6.54	6.75
OpenVMS	0.81	0.64	0.31	0.23	0.21	0.10	0.06	0.06	0.04

Courtesy of Gartner/SunMicrosystems

4.5 INDUSTRY CONSULTANTS

Industry consultants offer an important opinion on the trends in the IT industry, strategic directions that companies are taking with respect to their infrastructure, and vendor plans for their product lines.

Opinions expressed by consultants on the future of OpenVMS range from negative to cautiously optimistic. There is a consensus that Hewlett Packard will honour the original roadmap for OpenVMS and continue with the plans to port the operating system to the Itanium processor. However, there is some uncertainty as to whether the independent software vendors (ISVs) and customers in general will follow suit.

4.5.1 Gartner Group (http://www.gartner.com/)

Founded in 1979, Gartner provides combines more than 20 years experience identifying and analyzing the trends and technologies that have shaped the course of business. With more than 650 analysts around the world, Gartner has one of the most comprehensive bodies of global research that reports on and analyzes the technologies that drive business and organizational success.

In March 2002, prior to the Hewlett Packard/Compaq merger, Gartner Group allocated a “strong negative” rating to the OpenVMS operating system. A number of reasons were behind this rating.

1. At the time, details around which Itanium platforms would support OpenVMS were not clear.
2. HP-UX was seen as the dominant midrange operating system for the two companies.
3. Gartner believed that one result of the merger would be an exercise in cost cutting.
4. OpenVMS was seen as having a loyal but diminishing install base.

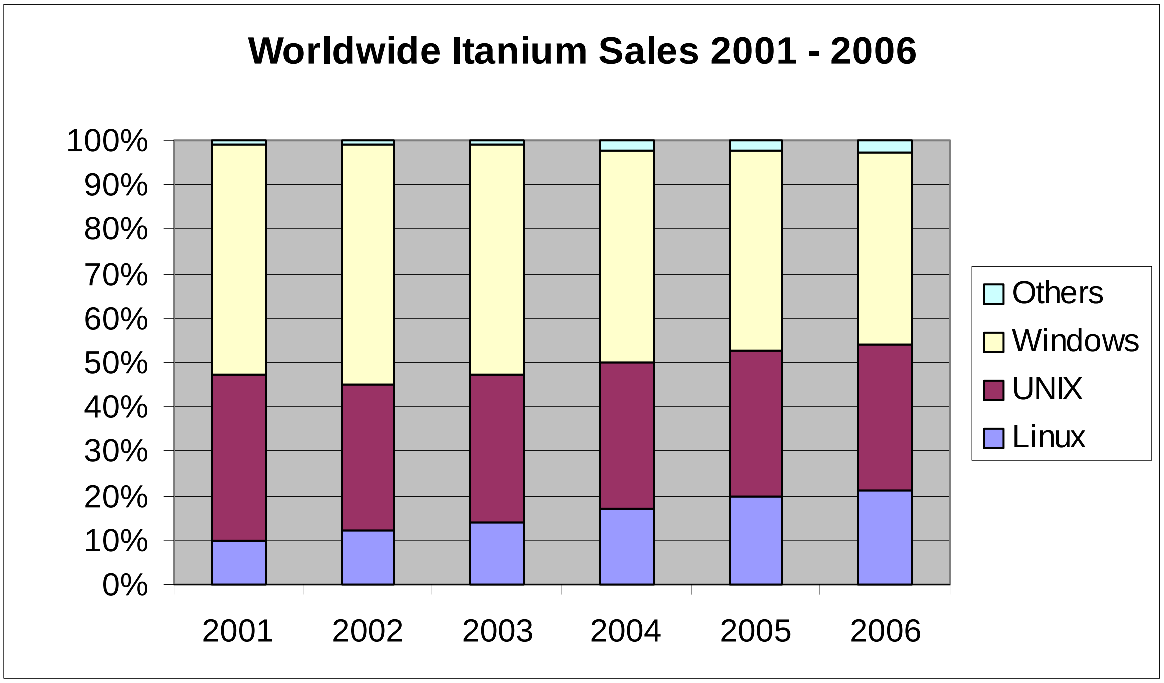
The merger affirmed Compaq’s commitment to porting OpenVMS to Itanium by 2004. As a result, Gartner revised its overall rating to “caution”. The “negative” rating still applied to any new business solutions. However, since OpenVMS has a wide base of in-house developed applications among its customers, the erosion of the ISV support was seen as not having as significant an impact as it would have if organizations were looking to buy packaged applications from ISVs.

One announcement from the merger was that components of Compaq’s UNIX version, Tru64, will be integrated into HP-UX on Itanium. Sales of Tru64 will continue until 2006. This action reiterates the view that HP-UX will become the dominant midrange operating system for Hewlett Packard.

Gartner predicts that even though Itanium will extend the life of OpenVMS, sales can expect to drop off after the Alpha processor is removed from marketing around the middle of the decade. After 2005, few new OpenVMS enhancements can be expected on either Alpha or Itanium.

Gartner also predicts that instead of porting their applications to Itanium, many existing OpenVMS customers will migrate to other platforms such as Windows or UNIX.

The table below details the projected sales of Itanium based systems from 2001 – 2006.



Courtesy of Gartner Group

Table 12 – Worldwide Itanium Sales from 2001 - 2006

In the chart above, OpenVMS sales fall into the "Others" category along with operating systems such as Netware. As shown, OpenVMS is not expected to make any appreciative impact to Itanium sales up to and including 2006. In 2006, OpenVMS will account for less that 2.5% of Itanium sales.

4.5.2 Giga (http://www.gigaweb.com)

Giga Information Group, Inc. is a global advisory firm that helps companies and institutions maximize their technology investment to deliver business results through a combination of objective research, advice and continuous technology coaching. Giga relies on experienced technology analysts who provide practical, action-oriented advice and recommendations that are based on professional experience and industry analysis.

Giga presents a more optimistic view of the future of OpenVMS. Their view is that potential immense backlash from existing OpenVMS customers may be enough for Hewlett Packard not to discontinue marketing and supporting the operating system.

Giga anticipates some customer uncertainty with many customers waiting until OpenVMS on Itanium is firmly entrenched before they consider migrating to the new processor. With an OpenVMS/Itanium general availability date around 2004-2005, migrations may not occur for up to 12 months after.

Although an early release version of OpenVMS will be created on Itanium in 2003 and made available to selected customers, Giga anticipates that a general release version will not be available for 2 years (2005).

With the merger announcements for Hewlett Packard and Compaq, customers can expect feature enhancements for at least the next three years and at a minimum a 10-plus year usable life for OpenVMS.

Despite customer uncertainty around OpenVMS, Giga categorizes those who have stated that they intend to remain on OpenVMS for the next 12 months as either:

1. OpenVMS customers who have no immediate plan to migrate but rather intend to modernize their existing legacy applications.

2. Companies who are content with the high availability and reliability of the OpenVMS environment but are not planning to deploy new OpenVMS/AlphaServer applications.

3. Companies that support the newest versions of OpenVMS and AlphaServers but in the future may migrate to either a Windows or UNIX alternative.

4.5.3 Other IT Industry Consultants

Other IT Industry consultants are not concentrating research on OpenVMS. Reference to OpenVMS is usually found in research on the Hewlett Packard/Compaq merger.

META Group

There has been little coverage of OpenVMS within the META Group research documentation in the last 12 months. The last reference to OpenVMS was in November 2001 and was part of an article on the Hewlett Packard/Compaq merger.

Forrester Research

The last reference to OpenVMS was made in an article about the Hewlett Packard/Compaq merger. The research was conducted in September 2001 and stated that with the additional service professionals, the new company may be in a better position to retain, satisfy, and upsell existing OpenVMS customers.

Aberdeen Group

The Aberdeen Group anticipates that Itanium will be successful as a technology. However, Aberdeen warns that Hewlett Packard should not attempt to port OpenVMS to Itanium. Aberdeen expects that migrating the traditionally loyal Digital and Compaq customers from OpenVMS to Itanium will be a “hard sell”. The consulting firm also feels that OpenVMS has been in a “maintenance mode” for several years with new functionality being developed simply to maintain its existing customer base.

4.5.4 Trade Journals

While conducting research, IT trade journals were investigated to determine frequency of articles concerning OpenVMS. It was found that recent references to OpenVMS tended to be made indirectly. Most articles that referenced to OpenVMS could be categorized as one of the following:

1. Articles on the Hewlett Packard/Compaq merger and the impact on each company’s line of products.

2. Articles focused other hardware or software technology in which OpenVMS is referenced as being compatible or incompatible with the technology.

There were few articles that focused on OpenVMS except in OpenVMS journals. Unlike Windows and UNIX, there is a lack of coverage and hype/excitement about OpenVMS.

4.6 INDEPENDENT SOFTWARE VENDORS

The announcement of the porting of OpenVMS to the Itanium processor has resulted in many of the existing Independent Software Vendors (ISVs) for OpenVMS proclaiming their ongoing support for OpenVMS. Two of these ISVs have particular significance to the OpenVMS environment at Newfoundland Power. These are Oracle Corporation and Cognos.

4.6.1 Oracle (http://www.oracle.com/)

Oracle has stated that it intends to continue support for the OpenVMS environment.

"Oracle and Compaq have a long and successful history of delivering enterprise solutions to our OpenVMS customers. In July 2001, Oracle released Rdb 7.1 for OpenVMS. In September 2001, Oracle9i for OpenVMS was released. Compaq has announced plans to consolidate its 64-bit servers on Itanium™ based systems. Oracle is committed to working with Compaq on its enterprise platform offerings, which includes working to deliver Oracle DBMS and Oracle Rdb DBMS on OpenVMS for Itanium™ based platforms."

Doug Kennedy, Vice President, Global Platform Partnerships, Oracle Corporation
September 2001

Despite the commitment from Oracle to continue deploying its products on OpenVMS, Oracle has relegated the OpenVMS operating system to a Tier 2 status platform for its database (Vendor Tiering is used as a designation to differentiate the best manufacturers from their competitors. Tier 1 vendors have the highest quality products, proven track records, solid support models, industry certifications like ISO-9000, and large strategic business relationships with their vendors and customers. Tier 2 vendors are often more-limited in product or technology, may be more limited in breadth of third-party service and support capabilities and typically represent a higher risk to customers than Tier 1. (Source, Gartner). The latest version of Oracle database product, Oracle 9.2 Enterprise Edition, has been released and certified on a number of operating system platforms. The table below shows the release dates for various midrange and Windows environments.

Oracle 9.2 Enterprise Edition Release and Certification				
Operating System	Availability	Certification	Release Date	Patch Release Schedule
Solaris	Y	Y	June 2002	Tier 1 release
AIX	Y	Y	June 2002	Tier 1 release
OpenVMS	N	Y	October 2002	Tier 1 release + 6 weeks
HP-UX	Y	Y	June 2002	Tier 1 release
Linux (Red Hat)	Y	Y	June 2002	Tier 1 release
Windows 2000	Y	Y	June 2002	Tier 1 release
Windows NT	Y	Y	June 2002	Tier 1 release

Table 13 - Oracle 9.2 Enterprise Edition Release and Certification

As shown in the table above, Oracle 9.2 Enterprise Edition is available on the major midrange and Windows operating systems. However, it is not scheduled to be released on OpenVMS until at least October 2002.

The table also indicates the scheduling for the release of software patches and program fixes. Once a patch has been released for the Tier 1 platforms, it will be another 6 weeks before it becomes generally available for OpenVMS customers. As a result, OpenVMS customers can expect to have to wait longer than other customers to receive software fixes. A Oracle Technical Assistance Report (TAR) confirming the Tier-2 status of OpenVMS can be found in Appendix B.

4.6.2 Cognos (http://www.cognos.com/)

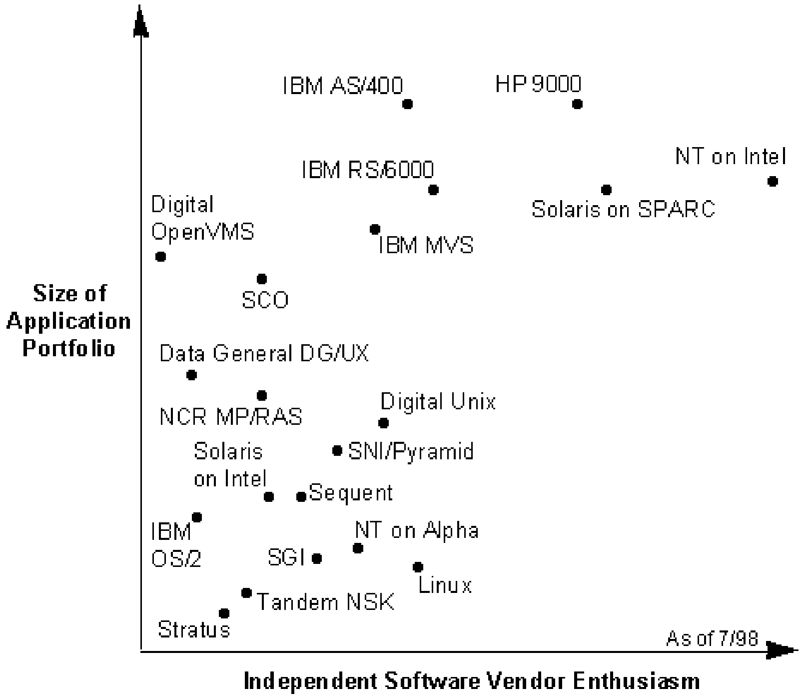
Cognos is one of the largest vendors of business intelligence software. Its product line assists users in extracting data, analyzing it, and then creating reports. The company's product PowerHouse is in use on the OpenVMS servers at Newfoundland Power.

In an interview with **xwave**, Marianne Stagg from Cognos stated that Cognos supports the migration of OpenVMS to Itanium. She also said that while some Cognos clients have migrated from OpenVMS to a Windows environment, the highest number of Cognos Powerhouse customers are on HP-UX, followed by OpenVMS.

Currently, Powerhouse version 8.4 is in beta on HP-UX. An OpenVMS beta version will be tested in August with a general release date to follow in October. Cognos has declared that OpenVMS is a Tier 1 operating system for Powerhouse.

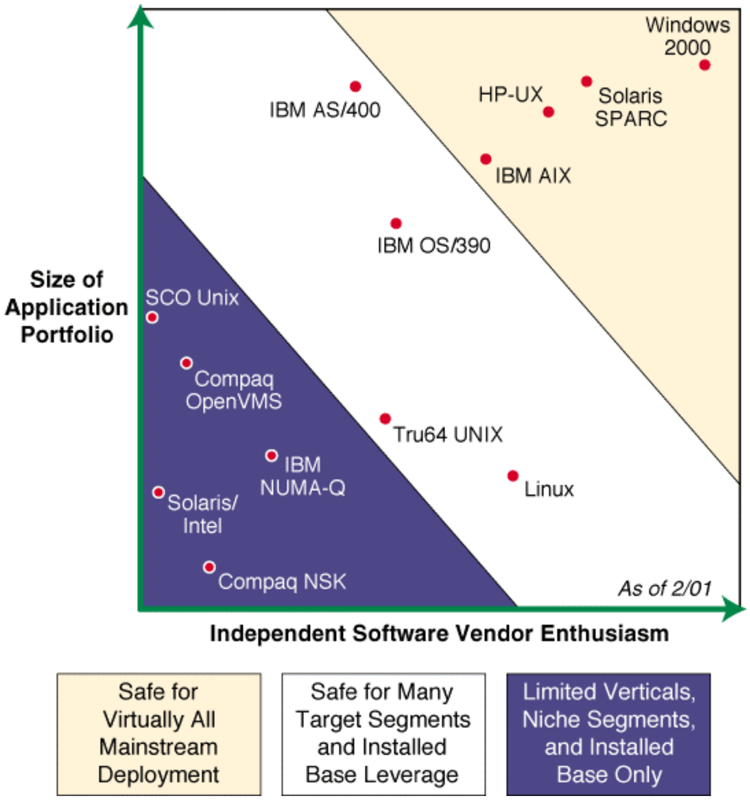
4.6.3 ISV Enthusiasm

According to the Gartner Group, ISV enthusiasm for OpenVMS is at best, not growing, and at worst, eroding. In March 2002, prior to the Hewlett Packard/Compaq merger, Gartner Group allocated a “strong negative” rating to the OpenVMS operating system. After the merger, Gartner revised its overall rating to “caution”. The “negative” rating still applied to any new business solutions. Despite the 100 ISVs proclaiming support for OpenVMS on Itanium, ISVs may not follow Hewlett Packard’s lead and instead opt to concentrate on developing their applications on more Open-Standards based operating systems or on OS’s with a higher percentage of market share. The charts below show the level of ISV enthusiasm for the various operating systems in the midrange marketplace in 1999 and again in 2001.



Courtesy of Gartner Group

Table 14 - ISV Enthusiasm for Midrange Operating Systems 1999



Courtesy of Gartner Group

Table 15 - ISV Enthusiasm for Midrange Operating Systems 2001

The two charts indicate that the ISV enthusiasm for the UNIX and Windows operating systems is much higher than that for OpenVMS. These operating systems are viewed as more mainstream than niche OSs such as OpenVMS and IBM's NUMA-Q. As well, there has been no growth in the ISV enthusiasm for OpenVMS from 1999 to 2001. The lack of increase in ISV enthusiasm indicates that OpenVMS has stalled in its growth in numbers of new applications being developed for the operating system.

4.6.4 Application Providers

The prime mission critical application currently located on the OpenVMS servers at Newfoundland Power is the Customer Support Service (CSS) application. While there is no definite timeline for the replacement of the CSS application, eventual replacement of the custom-built application will be necessary. In keeping with the IS Department's guiding principles to "Buy instead of build" and "Buy from leading vendors", **xwave** conducted research into the leading application providers of CSS and Customer Information Service (CIS) systems.

Through interviews and documentation, **xwave** found that major CSS and CIS providers were supporting Windows NT/2000 and UNIX platforms as application servers.

The table below details some of the leading application providers and the platforms on which their products are supported.

CSS / CIS Application Providers			
Vendor	Application	Supported Application Platform	Supported Database
Great Plains		Windows NT Windows 2000	SQL Server
PeopleSoft	CIS	Windows 2000 Windows NT4 AIX 4.3 HP-UX 11 Solaris 7 Solaris 8 Tru64 UNIX 5.0A Tru64 UNIX 5.1	SQL Server DB2 Oracle Sybase Informix
SAP	SAP	Tru64 UNIX AIX HP-UX Linux Reliant UNIX Solaris Windows 2000 Windows NT OS/400 OS/390	DB2/UDB/400/390 Informix SQL Server Oracle SAP DB
Advanced Utility Systems	CIS Infinity	Windows NT	Oracle SQL Server
Peace Systems	Energy Suite	UNIX	Oracle Informix
Oracle	11i Applications	Macintosh OS (client only) Tru64 UNIX Fujitsu PRIMEPOWER HP-UX AIX Intel Based Server LINUX Windows 2000 Windows NT for Intel Solaris	Oracle
JD Edwards	One World	AIX Solaris HP-UX OS/400 Windows NT Windows 2000	DB2 Oracle SQL Server

Table 16 - CSS / CIS Application Providers

Vendors who are supporting OpenVMS tend to support the platform for the database component only. One example of a CIS application vendor whose support for OpenVMS is diminishing is PeopleSoft.

PeopleSoft

PeopleSoft's CIS application is supported on the platforms in the above table. Like other vendors, the current version of the PeopleSoft, product line, PeopleSoft 8, supports OpenVMS for the database component only.

Earlier versions of the PeopleSoft products were supported on OpenVMS for the batch and database server components, depending upon customer demand. For example, PeopleSoft versions 5, 6 provided batch server support for OpenVMS. Versions 7.0 to 7.55, however, did not support OpenVMS because of the lack of customer demand for OpenVMS based versions of the batch server software. Support for batch services was reinstated in version 7.59 but discontinued in version 8. In contrast, the Solaris operating system has been supported for all components of the PeopleSoft product line since version 1.0.

4.7 XWAVE INTERNAL RESEARCH

As part of the research into the prevalence and direction of OpenVMS, **xwave** was able to tap into a number of internal resources that could offer insight into the OpenVMS industry. These resources included:

- Sales teams
- Resource coordinators
- Technology consultants
- Server support resources
- Trainers
- Recruiters

4.7.1 Sales Teams

An investigation of **xwave** sales activity within Atlantic Canada has shown that in August 2002, xwave received a request to provide four OpenVMS workstations/servers for a local customer. These computers will be deployed in South America as part of a niche, offshore oil application. Prior to this order, the last new OpenVMS server sales occurred in January 2001. AlphaServer sales were limited to the sale of replacement parts.

In contrast, the Sales teams within Atlantic Canada alone have sold hundreds of Intel and UNIX based solutions in the last 18 months.

An important component to the Sales teams is the responding to Requests For Proposals (RFPs) put out by customers requiring IT solutions to their business requirements. **xwave**'s Sales teams in Atlantic Canada have not identified any OpenVMS opportunities or RFPs in the last year.

4.7.2 Resource Coordinators

xwave's clients often require the services of our IT professionals in order to build or support IT solutions, and to provide consulting services. As a result, there are many requests for **xwave**'s technology consultants and server support resources. These requirements are funnelled through the **xwave** Account Management who in turn direct the request to a centralized Resource Coordination group. This group tracks the requests and matches resources to the requirements.

The table below details the number of requests received by the **xwave** Resource Coordinators in 2001 – 2002.

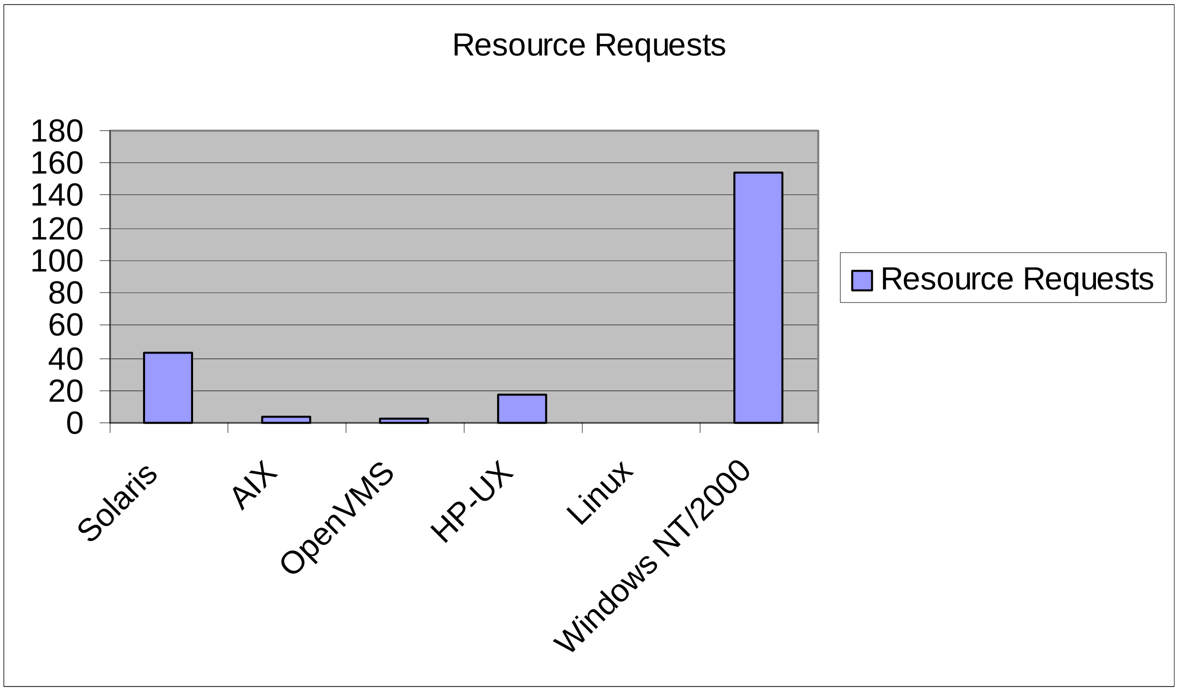


Table 17 - Resource Requests for 2001 – 2002

Throughout 2001 and up to the first half of 2002 there were 154 Windows NT/2000 resource requests issued to the Resource Coordination group. This number contrasts sharply with the two requests issued for OpenVMS resources. One of the latter requests was issued on behalf of Newfoundland Power and was for a DBA resource with OpenVMS experience. The other request was for a client in Ontario and was issued in 2001.

4.7.3 Recruiters

Every year **xwave** receives thousands of resumes from IT professionals. Since **xwave** is located throughout Canada, the United States, and Europe, the resumes represent a cross section of the IT community.

An investigation of this repository of resumes has produced information on the types of skills that are present in the IT industry. The table below details the numbers of resumes with various OpenVMS, UNIX, or Windows based skills.

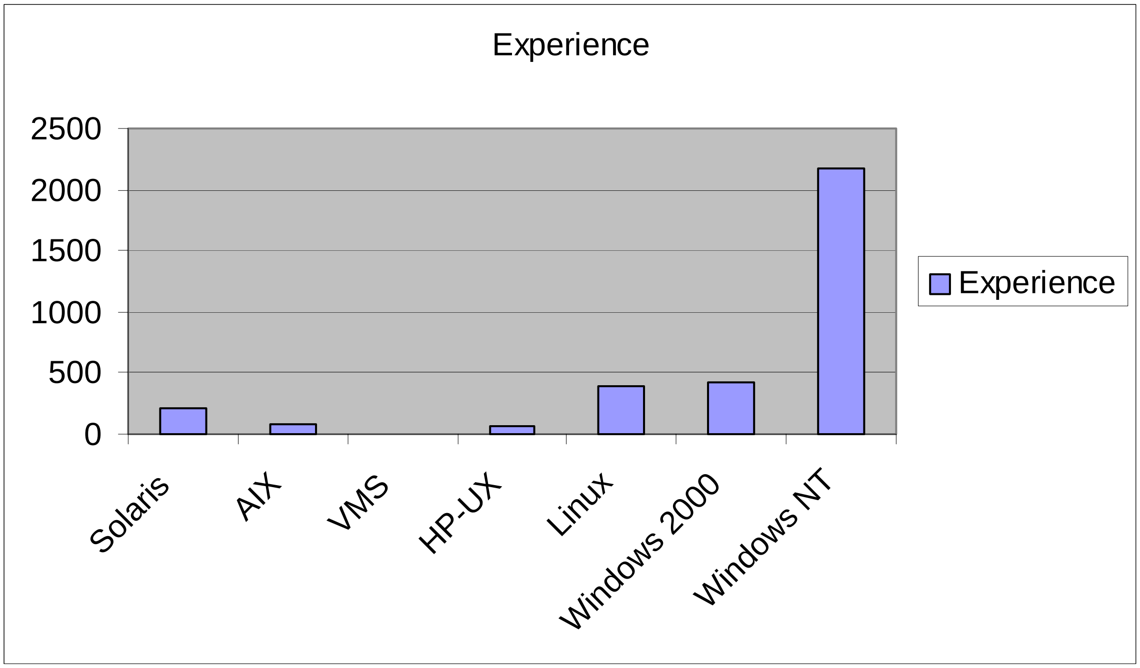


Table 18 – Operating System Experience on Resumes

Of the 3000 resumes online, only seven indicated that they had any OpenVMS (or VMS) experience. This is in sharp contrast to the nearly 2200 claiming to have some Windows NT experience.

It is estimated that approximately 60% of the resumes online at **xwave** are from people who have recently graduated from post secondary institutions. This indicates that very few graduates are entering the workforce with any OpenVMS experience. The research also shows that there are very few OpenVMS skills available for hire in the IT industry.

4.8 INDUSTRY

Through a series of customer and account manager interviews, **xwave** was able to develop some insight into our clients' views on OpenVMS.

xwave's customer base spans a large number of industries, and research information was gathered from a cross section of these industries. The customers that were specifically referenced in this report were chosen because:

The customers were based in Atlantic Canada and therefore could reflect the Atlantic Canada Information Technology landscape.

- The sizes of the server environments were comparable to Newfoundland Power's computing environment.
- The customers were relevant to Newfoundland Power because they were utility companies or public institutions.

Most of the customers who had OpenVMS applications have had them in place for at least 5 – 10 years. Many of these systems were upgrades from older VAX/VMS applications. Many of the OpenVMS servers were "tucked away in the back of the computer room".

Customers who were looking to replace the applications on the OpenVMS based servers were considering migrating to other operating systems such Windows 2000, HP-UX, or Solaris if the newer applications were available on these platforms.

While most customers were pleased with the level of availability and reliability of their OpenVMS systems, OpenVMS was not seen as a strategic operating system for deploying new mission critical applications.

4.8.1 The Fortis Group of Companies (http://www.fortisinc.com/)

Members of the Fortis Group of Companies include Newfoundland Power, Maritime Electric, Canadian Niagara Power, and Fortis Properties. The Corporation also holds a 67% interest in Belize Electricity and a 22% interest in Caribbean Utilities. Newfoundland Power is the only company in the Group that currently has production OpenVMS systems in place.

OpenVMS is not considered a strategic operating system within the Group. Microsoft Windows 2000 and the various UNIX versions are the preferred platforms for new applications.

4.8.2 College of the North Atlantic (CONA - http://www.northatlantic.nf.ca)

The college currently has only two OpenVMS systems in place. The AlphaServer 4100s run the College's business systems. The first AlphaServer was purchased in 1997 and served CONA for 4 years before capacity problems arose. To facilitate a solution, the College had to purchase a second AlphaServer. With the 4100 series not longer available through Compaq marketing, the College was forced to acquire a refurbished server from the United States. Once installed, the second server was used to alleviate some of the capacity problems encountered in the original server.

CONA considers its OpenVMS servers to be a solid and reliable environment. However, the College feels that the OpenVMS operating system has no future. The College is actively looking to replace its legacy business systems with newer ERP packaged solutions.

> *"The new Business solutions at the College will not be OpenVMS based."*
> **Wayne Hann, Manager of Information Services, CONA**
>
> **July 2002**

While CONA has never offered OpenVMS courses, students were exposed to VMS utilities such as editors and compilers as a means of compiling programs and learning about software development in that environment. This approach ended in 1997. Since then, students were exposed to software development tools/environments mostly on Windows or UNIX platforms.

4.8.3 Newfoundland and Labrador Hydro (http://www.nlh.nf.ca/)

Newfoundland and Labrador Hydro has no OpenVMS systems in production. The company's administrative systems operate primarily on Windows NT and Windows 2000 platforms. Its SCADA data is managed through the Harris Energy Management System, which operates on a proprietary Harris operating system and server.

4.8.4 Memorial University of Newfoundland (http://www.mun.ca/index.php)

While the Department of Computing and Communications (C&C) at the University had VMS systems in production in the 1980s and 1990s, most were replaced by 1998. The only remaining production application that resides on OpenVMS today is on a server that does not have a maintenance contract in place. C&C has made the decision to use UNIX for their deployment and subsequently has moved all other applications off OpenVMS, cancelled the software and hardware maintenance on OpenVMS, and removed the AlphaServers. Sun Microsystems' Solaris is the preferred UNIX operating system for enterprise applications such as the University Portal, the Web Course Tool (WebCT), and the Banner Financial and Student Administration systems. A combination of Solaris and Linux is chosen for other applications.

> *"I have no plans to use OpenVMS in the future."*
> **Randy Dodge, Manger of Technical Support, MUN**
> **July 2002**

4.8.5 New Brunswick Power (http://www.nbpower.com/)

New Brunswick has production OpenVMS 5.5-2 applications. Version 5.5-2 is seven releases behind the current OpenVMS 7.3-1. Newfoundland Power receives no formal support from Hewlett Packard for this version. However, Hewlett Packard provides the Utility "Best Efforts" support at a charge of $250 per hour. Old VAX systems have been purchased in an effort to have replacement parts on site.

While seven “important” systems at the Utility are OpenVMS based, OpenVMS is not viewed as a strategic operating system. As older applications are retired, the new replacements are being deployed on Windows NT and 2000 servers.

4.8.6 Atlantic Lotto (http://www.alc.ca/)

During the 1990s, Atlantic Lotto developed its mission critical gaming engine on OpenVMS servers. The gaming engine must be available at all times, because an outage interrupts the Lotto’s revenue stream. However, the Corporation is now in the process of porting its application to Windows NT and Linux. A successful business case for the porting was developed and was based upon the future of OpenVMS.

Atlantic Lotto still has production OpenVMS systems but intends to eventually migrate its applications off OpenVMS.

The table below details some of **xwave**’s customers who were polled to see if they deployed OpenVMS as production systems.

Customer	Production OpenVMS Systems	Predominant Operating Systems in Production
Fortis	Yes	Windows 2000 UNIX
College of the North Atlantic	Yes	Windows NT/2000 Linux
Newfoundland and Labrador Hydro	No	Windows NT/2000
Memorial University	Yes	Windows NT/2000 UNIX
New Brunswick Power	Yes (VMS)	Windows NT/2000
Atlantic Lotto	Yes	Windows NT/2000
Nova Scotia Power	No	Solaris Windows NT/2000
Maritime Life	No	Windows NT/2000 AIX HP-UX
Blue Cross	No	HP-UX

Table 19 - Operating Systems at xwave Customer Sites

4.9 EDUCATION CENTRES AND THE JOB MARKET

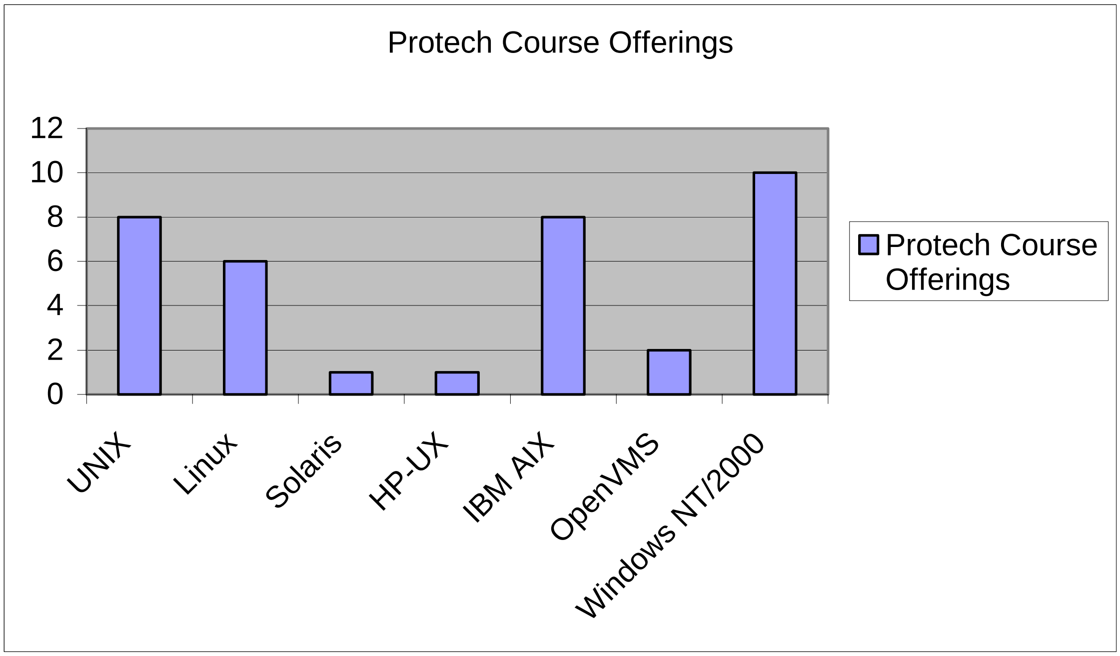
4.9.1 Education centres

Education centres and training companies offer a wide array of training courses for companies. The most popular, or “hot”, courses reflect what skills are in demand in the IT industry. Currently, the hottest courses are in the Windows, Database, and UNIX categories. Many learning centres are not offering OpenVMS curriculum.

Polar Bear Corporate Education Services, (http://www.polarbear.com/) formally Broadleaf, does not offer any OpenVMS training in Newfoundland. In contrast, they offer Windows NT/2000 courses approximately every 1.5 months.

Learning Tree International (http://www.learningtree.ca/), has never offered OpenVMS training to its customers. It has 13 Windows NT/2000 courses in its catalogue with courses starting in Ottawa or Toronto every week.

ProTech (http://www.protechpts.com/), a Pennsylvania-based IT training company that offers over 300 courses in the United States and Canada, has a curriculum that includes OpenVMS, Windows, and UNIX courses. The table below details the number of courses in each area. At this point, ProTech has no OpenVMS courses scheduled for the remainder of 2002.



Courtesy of ProTech

Table 20 – ProTech Course Offerings

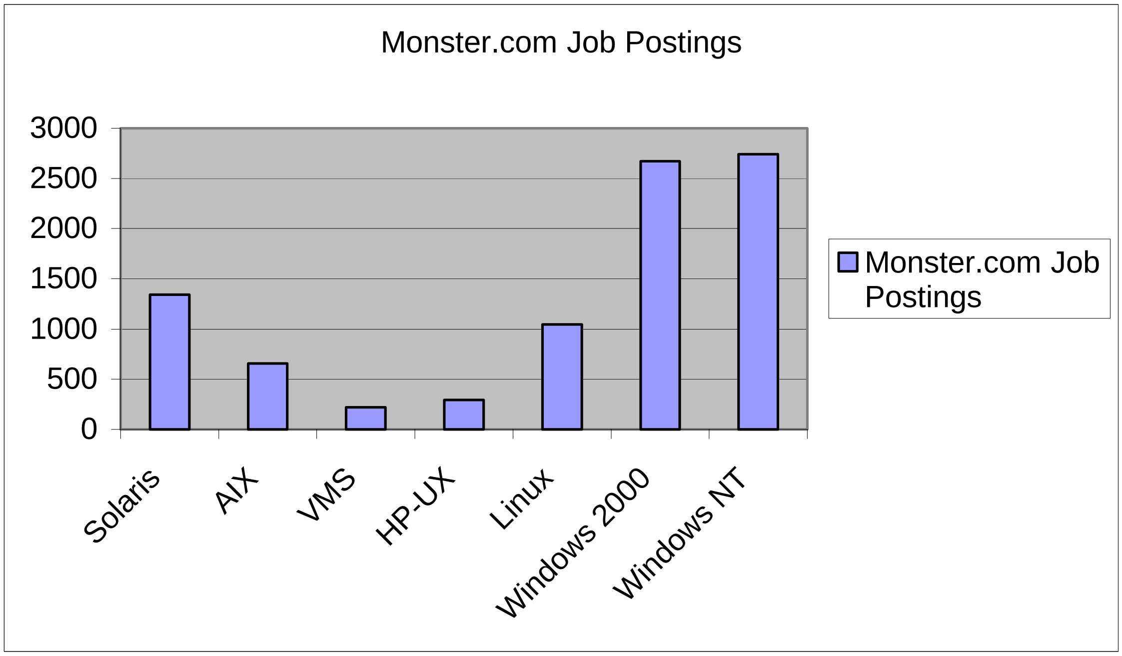
The College of the North Atlantic (http://www.northatlantic.nf.ca/) has never offered OpenVMS courses. The students, however, were exposed to VMS utilities such as editors and compilers as a means of compiling programs and learning about software development in that environment. This approach ended in 1997. Since then, students were exposed to software development tools/environments mostly on Windows or UNIX platforms.

Hewlett Packard (http://www.hp.com/) currently has OpenVMS courses available but at this point there are no classroom training scheduled to be held in Canada.

4.9.2 Job Market

An important indicator of the prevalence of OpenVMS can be found in the job market. Online companies that host IT professionals' resumes provide insight into the IT skills that employers can expect to gain when hiring new employees as well as the job available in various IT areas.

One of the leading Job Market services is Monster.com (http://www.monster.com). The table below shows the number of jobs listed on Monster.com that require some experience with various operating systems.



Courtesy of Monster.com

Table 21 – Job Postings on Monster.com

The table indicates that there is a much higher demand for IT professionals with Windows or UNIX skills. As well, the number of job postings indicates the prevalence of the various operating systems in the North American job market.

5.0 ALTERNATIVES

Newfoundland Power has three alternatives to choose from in deciding the direction of the OpenVMS computing environment:

1. Remain on the existing OpenVMS AlphaServer 4100 platforms until OpenVMS on Itanium is generally available. Then, migrate the existing applications over to the new technology.
2. Purchase new AlphaServers and migrate the in-house applications over from the 4100 servers.
3. Migrate away from the OpenVMS environment and towards the Windows or UNIX environments.

5.1 REMAIN ON THE EXISTING OPENVMS ALPHASERVER 4100 PLATFORMS

Newfoundland Power could decide to remain on the existing AlphaServers until at least 2005 and then port the OpenVMS operating system and the applications to a new set of Itanium servers. However, the age of the servers and the timeframe between the 2002 and 2005 presents a high level of risk to Newfoundland Power for a number of reasons.

5.1.1 AlphaServer 4100 End-of-Life on Marketing

The AlphaServers 4100 at Newfoundland Power have been removed from marketing by Compaq. As a result, it is becoming increasingly difficult to obtain quality replacement parts for the servers. Recent AlphaServer purchases have been for refurbished components.

5.1.2 Performance Issues and Availability of Parts

In 2001, DRACO encountered performance problems. To alleviate the issue, memory was removed from the disaster recovery server CORVUS, reducing its total memory to 4GB. This action had two consequences:

1. In the event of a disaster recovery scenario for DRACO, its DR server would not be able to provide the same level of performance that was earlier anticipated. Removing memory from CORVUS leaves it two GB less that DRACO.
2. The addition of 1GB of memory to DRACO filled the system board for the server. Therefore, no more memory can be added to DRACO unless another system board is added or original memory is replaced by higher density memory.

A midrange server has a useful life of approximately 4-5 years, provided the original configuration allows for additional capacity growth. The newest AlphaServers at Newfoundland Power was purchased in 1998. The oldest, CYGNUS was acquired in 1995. Newfoundland Power can no longer rely on the disaster recovery servers for reliable replacement parts because, with the exception of VOLANS, they are as old or older than the primary production and development servers.

Newfoundland Power may decide to remain on the existing servers. By doing so, it will have to assume the risk associated with leaving its mission critical CSS application on servers that will be at least 7 years old before OpenVMS on Itanium is available. Maintaining these existing systems until 2005 would jeopardize the mission critical environment.

5.1.3 Itanium Uncertainty and Niche Market

Hardware vendors have begun to market Itanium servers. Intel has just released the second generation of Itanium, the Itanium 2 processor. However, there is still customer uncertainty around the success and cost effectiveness of Itanium. Itanium has yet to gain wide mainstream status. Many customers will be content with the less expensive processors. As well, there could be performance degradation when customers run 32-bit applications on Itanium's 64-bit architecture

Giga states that Itanium will be seen as a solution for software development and high performance technical computing. Gartner anticipates that most of the Itanium 2 customers will be focused on software development, testing, proof of concept, and some technical computing.

Newfoundland Power may find that it can deliver its applications to its clients on less expensive technology than the Itanium family of processors.

5.1.4 Oracle Server Support and New Version Requirements

The current version of Oracle Server on the OpenVMS platforms at Newfoundland Power is Oracle Enterprise Edition 8.1.6 (8i). This version is currently in Extended Assistance Support (EAS) status. EAS includes the follow types of support:

- Telephone and Electronic support, consisting of:
  - Answers to customers' questions
    - Assistance with migration plans to a supported platform and/or product
    - Workarounds, where possible

However, EAS does not provide:

- Error Correction Support (ECS) - No new bug fixes
- Backporting of fixes
- Certification with supported products, newer operating system versions or new compilers
- Escalation support, response time adherence and skill availability

This means that Oracle will only provide existing fixes to Newfoundland Power. As well, fixes found in newer versions of Oracle will not be applied to Oracle 8.1.6. Perhaps most important is that Oracle will not escalate any support requests from Newfoundland Power while 8.1.6 is installed.

EAS will no longer be available after October 2004. The Oracle Desupport Notice is in Appendix C.

Newfoundland Power should migrate to the newer versions of Oracle Server. Version 8.1.6 is three releases behind the latest version. However, Oracle upgrades at **xwave** have shown that version 9i of the database product can consume up to 20% more system resources than previous 8i versions. As a result, Newfoundland Power may have to obtain additional systems resources such as CPUs, memory, and disk to accommodate the new requirements. This will be difficult with the existing AlphaServers.

Oracle Enterprise Edition Licensing at Newfoundland Power

It was not obvious why Enterprise Edition was purchased instead of Standard Edition. Standard Edition is less expensive than Enterprise. Standard Edition is sufficient for servers with a capacity for four CPUs, unless some of the features in the Enterprise Edition but not in Standard are required. A listing of the features in both editions is contained in the Appendix D.

5.2 PURCHASE NEW ALPHASERVERS

Newfoundland Power could purchase the latest Alpha technology from HP. Since the company has not budgeted for replacement of these servers in the 2002 fiscal year, purchases would not occur until at least April 2003. The servers would most likely come from the EV7 product family of servers. Once received, plans to configure the servers and the operating system would begin. The software toolsets such as COBOL, BASIC, and FORTRAN, and the Oracle database software would have to be installed. Applications would have to be ported over to the new servers, tested and then put into production.

5.2.1 AlphaServer Technology End-of-Life

In June 2001, Compaq announced the AlphaServer Roadmap that included information on the commitment to sell AlphaServers up to 2006 only. After the HP/Compaq merger in April 2002, HP reaffirmed the Roadmap. The two main operating systems that are on the AlphaServers is Tru64 and OpenVMS. Tru64 would be phased out in favour of HP-UX. OpenVMS will be ported to the new Itanium processor by 2004-2005.

If Newfoundland Power purchases the EV7 servers in 2003 and then goes through the process of bringing them online for the user community, then the company will be obtaining servers whose technology will most likely be obsolete in less than 3 years. The result of this action would be that the OpenVMS server environment would be in the same position as it is today – upgrades and replacement parts would become increasingly difficult to obtain.

HP will most likely focus its resources on the Itanium processor rather than the Alpha. This is evident in the fact that OpenVMS is being ported to Itanium and that unlike the Alpha processor, there has been no discussion about the retirement or end-of-life plans for Itanium.

5.3 MIGRATE AWAY FROM OPENVMS

The other alternative is to migrate Newfoundland Power's OpenVMS based applications towards Windows or UNIX environments. As shown in the research presented, the combination of a number of significant factors would limit the potential for OpenVMS to become a mainstream operating system in the midrange market.

5.3.1 Migration Alternatives

Migration away from OpenVMS can be accomplished either by attrition or by actively porting the legacy applications.

MIGRATION THROUGH ATTRITION

Attrition involves maintaining the existing OpenVMS environment for as long as the applications are in use. As replacement systems are purchased for the older legacy systems, they would be implemented in the Windows environment.

Following the "Buy not build" philosophy, the older code and toolsets would be abandoned and newer tools such as Visual Studio, C++, ASP, XML, and SQL Plus would be utilized. The tools would not be used to build in-house applications but rather to customize purchased solutions.

Because the new applications have not been identified, it is impossible to provide a technical architecture. Different vendor applications have different technical architecture requirements.

This alternative will be successful if the existing applications will be scheduled for replacement within the next 12 – 18 months. A longer timeline for replacement places the OpenVMS applications at the same risk level as simply remaining on the AlphaServers until Itanium has gained mainstream status.

Newfoundland Power's current plan is to replace all the applications on the OpenVMS servers except CSS by the end of 2003. Therefore, CSS is the only application that would have to be actively migrated from the existing servers.

ACTIVE MIGRATION

This alternative would involve the development of a migration plan to port the existing CSS software, application code and database to either the Windows or the UNIX environments. Such a solution would have to provide similar availability, reliability, and stability as currently provided under the AlphaServer platforms.

xwave has extensive experience in deploying applications on Windows and UNIX platforms. A discussion on the benefits and risks with each operating system can be found in the Appendix E.

5.3.1.1 MIGRATION TO MICROSOFT WINDOWS 2000

Newfoundland Power has standardized upon Windows 2000 operating system and Compaq Proliant servers for the deployment of Intel solutions. Therefore, Newfoundland Power should follow these standards when migrating systems from OpenVMS to Intel.

The migration to a Windows environment would result in a change in how the CSS application and the database are structured. The application and database services would be separated onto their own servers. One Compaq DL380 would host the production application while a larger Compaq DL580 would contain the Oracle database.

The creation of a second environment would host the development effort and at the same time act as a disaster recovery server infrastructure. This configuration maximizes the utilization of the disaster recovery servers while at the same time reduces the number of servers required to support.

The production servers would be housed at Duffy place. This places the CSS application close to the majority of users of the production system. The servers would connect to the Storage Area Network (SAN) solution proposed recently by **xwave**. As a result, 437 GB of external disk storage would be installed in the SAN for use by the production servers.

The table below details the server configurations for the production Windows environment. Costs include acquisition / product cost only.

Server Configurations for the Production CSS Windows Environment			
Component	Function	Configuration	Cost
Production Database Server	Database server for production application	Compaq DL580 2 X1600-1MB MHz CPUs 4 GB RAM 2 X 18.2 GB Disks Oracle licensing	$75,600
Production Application Server	Application server for production application	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 18.2 GB Disks Runtime software	$31,000
External Storage	External storage for production servers	437 GB disk storage (to be located in proposed SAN solution)	$9,200
Server Rack	Rack for production servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for production servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$132,800.00

Table 22 - Server Configurations for the Production CSS Windows Environment

The development servers would be housed at the Kenmount Road office. The servers have the same hardware and software configurations as the production servers in order to provide the same performance for users in the event of a production server failure.

The servers would connect to the Storage Area Network solution proposed recently by **xwave**. As a result, 437 GB of external disk storage would be installed in the SAN for use by the development servers.

Server Configurations for the Development / Disaster Recovery CSS Windows Environment			
Component	Function	Configuration	Cost
Development Database Server	Database server for development application	Compaq DL580 2 X1600-1MB MHz CPUs 4 GB RAM 4 X 72.8 GB Disks Oracle licensing	$42,800
Development Application Server	Application server for development application	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Compiler and Runtime software	$51,500
External Storage	External storage for development servers	437 GB disk storage (to be located in proposed SAN solution)	$9,200
Server Rack	Rack for development servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for development servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$120,500.00

Table 23 - Server Configurations for the Development / DR CSS Windows Environment

The tables above represent the requirements for migrating the CSS application. The existing OpenVMS environment hosts 10 other applications that are scheduled to be replaced before the end of 2003. Appendix F contains high-level server configurations to replace all existing OpenVMS applications at Newfoundland Power.

5.3.1.2 MIGRATION TO UNIX

UNIX can provide a level of availability, reliability, and stability that is comparable to OpenVMS.

As in the case of a migration to Windows, the UNIX production servers would be housed at Duffy place. This places the CSS application close to the majority of users of the production system.

The table below details the server configurations for the production UNIX environment. Costs include acquisition / product cost only.

Server Configurations for the Production CSS UNIX Environment			
Component	Function	Configuration	Cost
Production Database Server	Database server for production application	Sun SunFire V480 2 X 900 MHz CPUs 4 GB RAM 2 X 36GB Disks Oracle licensing	$88,200
Production Application Server	Application server for production application	Sun SunFire V480 2 X 900 MHz CPUs 4 GB RAM 2 X 36GB Disks Runtime software	$50,700
Storage Array	Storage array for production servers	Sun StorEdge D2	$19,400
Server Rack	Rack for production servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for production servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$175,300.00

Table 24 - Server Configurations for the Production CSS UNIX Environment

The UNIX development servers would be housed at the Kenmount Road office. Like the Windows alternative, the servers have the same hardware and software configurations as the production servers in order to provide the same performance for users in the event of a production server failure.

Server Configurations for the Development / Disaster Recovery CSS UNIX Environment			
Component	Function	Configuration	Cost
Development Database Server	Database server for development application	Sun SunFire V480 2 X 900 MHz CPUs 4 GB RAM 2 X 36GB Disks Oracle licensing	$55,500
Development Application Server	Application server for development application	Sun SunFire V480 2 X 900 MHz CPUs 4 GB RAM 2 X 36GB Disks Compiler and Runtime software	$50,700
Storage Array	Storage array for development servers	Sun StorEdge D2	$19,400
Server Rack	Rack for development servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for development servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$142,600.00

Table 25 - Server Configurations for the Development / DR CSS UNIX Environment

The tables above represent the requirements for migrating the CSS application. Appendix F contains high-level server configurations to replace all existing OpenVMS applications at Newfoundland Power.

6.0 RECOMMENDATIONS

The current OpenVMS servers at Newfoundland Power house mission critical applications. As a result, Newfoundland Power's ability to be a leader in electrical transmission and distribution services in North America is impacted if the applications become unavailable.

Analysis of the information presented in the preceding sections indicates that the future for OpenVMS as an operating system for critical business applications is limited. Despite assurances from Hewlett Packard, continuing to use OpenVMS contains an unacceptable level of uncertainty and risk. As well, the combination of a number of significant factors limits the potential for OpenVMS to become a mainstream operating system in the midrange market. **As a result of the analysis of the Project's research, xwave recommends that Newfoundland Power migrate away from the OpenVMS operating system environment and begin deploying its current OpenVMS based applications onto other operating systems.**

A migration of the OpenVMS based applications to a Windows or UNIX environment will place Newfoundland Power in a better position to provide an available, reliable, and stable computing environment for its applications in the future. These operating systems were chosen as alternatives because Newfoundland Power has experience with both - Windows through the deployment of applications such as the Great Plains application and UNIX through the Tru64 SCADA implementation. It is important to note that the configurations and prices reflect current technology as of August 2002.

By the end of 2003, all the applications on the OpenVMS servers except CSS will already have been replaced. Therefore, the configurations below represent a high-level infrastructure architecture to replace the current CSS infrastructure. Appendix F contains high-level server configurations to replace all existing OpenVMS applications at Newfoundland Power.

A Microsoft Windows 2000 alternative would involve the deployment of two production servers, as well as two additional servers that would accommodate application development and disaster recovery. The following table summarizes the server infrastructure and provides a high-level estimate of hardware and software required to implement this solution. Costs include acquisition / product cost only.

CSS Windows 2000 Environment		
Environment	Requirements	Cost
• Production	One Compaq DL580 database server One Compaq DL380 application server 437 GB external storage One server rack One communications switch	$132,800
Development / Disaster Recovery	One Compaq DL580 database server One Compaq DL380 application server 437 GB external storage One server rack One communications switch	$120,500
	Total (excluding tax)	$253,300.00

The servers would connect to the Storage Area Network solution proposed recently by **xwave**. As a result, 874 GB of external disk storage would be installed in the SAN for use by the servers.

A UNIX alternative would involve the deployment of two production servers, as well as two additional servers that would accommodate application development and disaster recovery. Costs include acquisition / product cost only.

CSS UNIX Environment		
Environment	Requirements	Cost
• Production	One Sun Microsystems Sun Fire V480 database server One Sun Microsystems Sun Fire V480 application server One Sun StorEdge D2 Array One server rack One communications switch	$175,300
Development / Disaster Recovery	One Sun Microsystems Sun Fire V480 database server One Sun Microsystems Sun Fire V480 application server One Sun StorEdge D2 Array One server rack One communications switch	$142,600
	Total (excluding tax)	$317,900.00

Both alternatives would include locating the production servers at Duffy Place. This places the CSS application close to the majority of users of the production system.

At this time, **xwave** does not make a recommendation between Windows 2000 and UNIX as the preferred alternative. The final decision on which platform to deploy depends upon the future direction of applications such as the Customer Support System (CSS). Specifically, future replacements for these applications will determine which operating systems should be used.

APPENDIX A – OPENVMS INFRASTRUCTURE TECHNICAL QUESTIONNAIRE

The following questions form a guideline of the type of information **xwave** is seeking during the information-gathering phase with the IT resources at Newfoundland Power. While additional questions may arise from the interview(s), the questions below will drive the discussions.

1. **How many OpenVMS servers are currently in operation?**

   Response:
   There are 3 Production and 3 Disaster Recovery/test servers.

2. **What is the function of each?**

   Response:
   One is the Customer Service System, another is the Financial Systems (being phased out), and the third is the Customer Service Development System and their Disaster Recovery backups.

   When are the Financial systems being phased out? What is the plan for the server?
   What will be the new platform (Is this the Great Plains project)?

   Response:
   Great Plains is the chosen solution. There is an implementation planned for Compaq servers for Great Plains. FASBE is the old financial system. CSS will be replaced in 3-5 years – development will NOT be done in house on the new CSS system.

3. **What corporate applications reside on each server?**

   Response:
   In-house developed and supported CSS, PCLS/Interruptions, JUS, SLMS, FASBE, SWITCH, SRS

   What is the function of each application? Are they all in-house developed? What are they developed in? Are these server centric, Client server, or web applications?

   Response:
   FASBE, SWITCH and SRS are located on the Financial Server. HRIS system (provided by StarGarden) interfaces with Great Plains. Acronyms are as follows:

   CSS – Customer Support System
   PCLS – Problem Call Logging System
   JUS – Joint Use System
   SLMS – Street Light Management System
   SRS – Spill Reporting System (a replacement of SRS is coming.)

4. **What software packages (and versions) reside on each server?**

   Response:
   OpenVMS Alpha 7.2-1, Cobol 2.6, Basic, Fortran, DECForms 3.1, DECnet 7.2-1, DECWindows Motif 1.2-5, CA AdviseIT agent and Manger 2.4, Process Software TCPWare 5.3-2, Cognos Powerhouse 820D3, WordPerfect/VMS 5.3+.

   Is this software on each server? What software is used for a database engine?

   Response:
   Cobol 2.6 is used on the Development server only
   PVCS runs on the Development Server
   DECNet is a file transfer protocol for OpenVMS
   Power have developed their own backup script for OpenVMS
   Use their network to backup during off-peak times (100MBit over 1GBit backbone)
      For NT Backup they use ARCServIT
      Backups are done at each site for the other location Duffy-Kenmount and vice versa
      Backups run nightly, full backup on the weekend
      6 tapes for monthly, 6 for weekly, 6 for daily
      DLT drives for each server
   Running Oracle 8.1.6 Enterprise – not sure why Enterprise instead of Standard
   200 licenses in total, multiplatform and split amojngst systems

   Database for CSS is ~ 20GB
      CSS developed in Cobol and Powerhouse, online component in Axiant

   Planning on a network upgrade next year between buildings

5. **How many FTEs (Full Time Equivalents) are required to support the OpenVMS servers?**

   Response:
   1

   Is this a single individual or is the support spread across multiple individuals?

   Response:
   ½ Keith Le Feuvre, ½ Sean Kearley

6. **How many FTEs are required to support the non-OpenVMS servers?**

   Response:
   2

Are these two individuals?

Response:
Upgrade of SCADA units (364's ?) soon – moving to NT platform

Topsail Road office has 2 Intel-based servers, 4 364's
8 regional offices have servers for File/Print/User Directory
Using BDC, SMS and TrendMicro (for viruses through Enterprise agreement via Fortis)

7. **What are the skillsets / certifications for the resources supporting the OpenVMS servers?**

   Response:
   Computer Science diploma. Additional training provided by DEC/ Compaq.

   Are the resources trained/experienced in the Wintel environment as well?

   Response: OpenVMS courses taken, as well as couses such as Cisco Administration

8. **Are there Change Management windows established for the servers?**

   Response:
   Yes.

   What is the schedule for CM (ex: one Sunday a month.)

   Response:
   Change Management procedures are rigorous for Production
   Schedule on a by-Request basis
   Developed CM application in VB and Access
   Most changes are implemented on Friday nights, allowing for weekend stabilization
   From 8pm-8am Friday night, batch processing, purge, archive and backup

9. **Are the servers currently under hardware and software Support Agreements with vendors? What levels of Support exist?**

   Response:
   Yes. Production Servers have 24 X 7 hardware and software maintenance. Disaster Recovery servers have 9 X 5 hardware maintenance.

   Same day or next business day on parts? How quickly the response call (4 hour?)

   Response:
   2 hour callback on support, 4 hour on parts

10. **Who applies hardware/software patches or repairs to the servers?**

Response:
Newfoundland Power performs software patches and upgrades in-house. Hardware repairs are performed by the Vendors and supervised by Newfoundland Power.

Hardware vendors allpy patches Oracle 8.1.7 on NT box, 8.1.6 on all servers
Plus SQL 2000

11. **What is the hardware configuration of each server (Model/CPUs/RAM/Disk storage/network connectivity, etc)?**

Response:
Draco: AlphaServer 4100 5/533, 2 CPU, 6 GB RAM, 226 GB 100 Mb/s
Prod1: AlphaServer 4100 5/466, 2 CPU, 2 GB RAM, 110 GB 100 Mb/s
Orion: AlphaServer 4100 5/300, 2 CPU, 1.5GB RAM, 125 GB 100 Mb/s
Corvus: AlphaServer 4100 5/533, 2 CPU, 4 GB RAM, 226 GB 100 Mb/s
Volans: AlphaServer 4100 5/466, 2 CPU, 2 GB RAM, 110 GB 100 Mb/s
Cygnus: AlphaServer 2100 5/250, 2 CPU, 1.28 GB RAM, 130 GB 100 Mb/s

Which are the production, development, and disaster recovery servers?

Response:
Draco = CSS
Prod1 = Financial
Orion = Development

Corvus, Volans and Cygnus are DR servers for respective Production servers

Years put into service:	*Draco – 1998*	*Prod1 – 1998*
	Orion – 1997	*Corvus – 1998*
	Volans – 1999	*Cygnus – 1995*

Everything on the server is backed up and if a restore is necessary, everything is restored (Full Volume)

Corvus, Colans and Cygnus are mirrors of the production servers respectively and are warm. In the event of a major upgrade or application migration, the event takes place on the DR servers Corvus, Volans and Cygnus which are then mirrored to the production servers.

12. **What type of disk storage is connected to the servers (internal/external subsystem/SAN)?**

Response:
Internal and external disk storage, Non SAN.

Compaq RAID Controller with 200GB on OpenStorage

Replacing soon with Compaq SAN

13. **When were the servers purchased?**

Response:
Earliest 1995, and the latest in 1998.

When were the last upgrades applied to the hardware? Have the servers started to be limited in their capacity for performance? Is there an evergreen plan for servers at Newfoundland Power?

Response:
See above notes …

An upgrade to the CSS server was done, adding Memory and Disk space

14. **Do you have any enterprise-wide hardware or software agreements with vendors that allow the installation of hardware/software at no additional charge?**

Response:
No.

15. **What are the expected level (%) and hours of availability for the servers?**

Response:
CSS system is 24X7. Financial System is 12X5. 100% during prime working hours of Monday to Friday 8am to 8 pm.

What is built into the servers to maintain the level of availability (mirroring, redundant PS and fans, clustering, etc?)
What is the expectation with the development server?

Response:
As noted above, 3 servers are warm "mirrors" of the production units. Worst case scenario is a 24hr restore. It takes approximately 8 hours to backup the Databases.

16. **How long can the servers be unavailable during any given outage?**

    Response:
    Maximum of one-half hour during prime time 8am to 8pm Monday to Friday except in rare emergencies. Scheduled outages can be longer on the weekends. Environmental consideration ie weather and or problems with the electrical grid will impact planned outages.

17. **What Disaster Recovery plans exist for the servers?**

    Response:
    All three production servers have disaster recovery plans and warm backup servers.

    Is there any clustering software on the servers? How are the backup servers maintained as "warm"?

    Response:
    All DR servers are Power On and drives are spinning. Backups are done Monday – Saturday 8pm-8am – 50-Step backup procedure completed to ensure no problems.

18. **Are the servers considered Production or Development servers?**

    Response:
    Two are production servers, and one is a Development/test server. Three are Disaster recovery and test servers.

19. **Is there any development activity currently being conducted on the servers or are they strictly in an operational mode?**

    Response:
    Yes see above.

20. **What interfaces exist between the OpenVMS servers and other systems at Newfoundland Power or external entities?**

    Response:
    TCP/IP interfaces primarily Cognos Axiant Client/Server connections, Telnet, NFS, SMTP, SNMP, and FTP.

    Are there any system Interfaces such as payroll?

    Response:
    CSS interfaces with FASBE / BOSS – most interactions are FTP flat file

CSS interfaces with the webserver (Oracle/NT) as an export form CSS

21. **Where are the OpenVMS servers physically located?**

    Response:
    4 are at Kenmount Road and 2 are at Duffy Place.

    4 at Kenmount are Draco, Orion, Prod1 and Cygnus
    2 at Duffy are Volans and Corvus

    There is a plan to place Draco @ Duffy and bring Corvus back to Kenmount

22. **Are there diagrams available that show the network location of the OpenVMS servers?**

    Response:
    Yes.

23. **What network protocols are used on the servers?**

    Response:
    DECnet and TCP/IP.

    What is DECnet used for that cannot be done by TCP/IP?

    Response:
    DECNet is used as an File Transfer Protocol for CSS to Great Plains

24. **How are the servers backed up? What is the frequency of the backups and approximately how much data is backed up?**

    Response:
    The servers are backed up using DLT tape drive and the tapes are taken off site to its Disaster Recovery site. Full backups are performed once per week and incremental backup on the other four days. Backups are coordinated and initiated by the Computer Room operators.

25. **Does Newfoundland Power have existing server and OS standards developed?**

    Response:
    Yes

Describe how OpenVMS fits into these standards.
Are these standards for choosing servers and OSs or in maintaining them?

Response:
Newfoundland Power only buys Compaq and Compaq Servers
Tier 1 Servers and PC's

26. **Are the OpenVMS servers monitored for availability? How is this done (scripts, HP OpenView, etc)?**

    Response:
    Yes with HP OpenView and in-house developed scripts.

    How is notification of a problem made (automated pager, message to a console, etc)? Is there afterhours support for the servers (anyone on call)?

    Response:
    Newfoundland Power uses custom developed Scripts which eMail notification to pagers on support staff. MS Exchange server is equipped with a paging module. SMTP or VMS for paging of other processes, HPOpenView Monitor pages to eMail or pager.

27. **Are the servers located in racks?**

    Response:
    Yes.

    Do you use standard 19" Compaq racks?

    Response:
    Non-standard racks as the AlphaServer 4100 is a wide-body server (much wider than Proliant series servers)

28. **Are there any contract implications to consider if the OpenVMS servers are no longer in use (e.g., any existing multi-year contracts)?**

    Response:
    No we have one-year contracts.

29. **What is the annual maintenance costs for the hardware and software on the OpenVMS platforms?**

    Response:

$145,000 Hardware, $283,000 Software.

30. **How many users/developers are on each server?**

    Response:
    85 users of CSS, 35 of Financial

    Where are they located (in Kenmount/Duffy, around the province)?

    Response:
    Users have Citrix MetaFrame – desktop client is 100MB
    Great Plains is Citrix based, not web-based

31. **Will the user community for each server expand within the next 2 years?**

    Response:
    No.

32. **Are there any plans to increase the hardware capacity or upgrade the software on the servers in the next 2 years?**

    Response:
    Yes. Purchase SAN for CSS, Memory for DR server, Upgrade OpenVMS, Oracle, Powerhouse.

33. **What are the reasons for wanting to migrate from OpenVMS?**

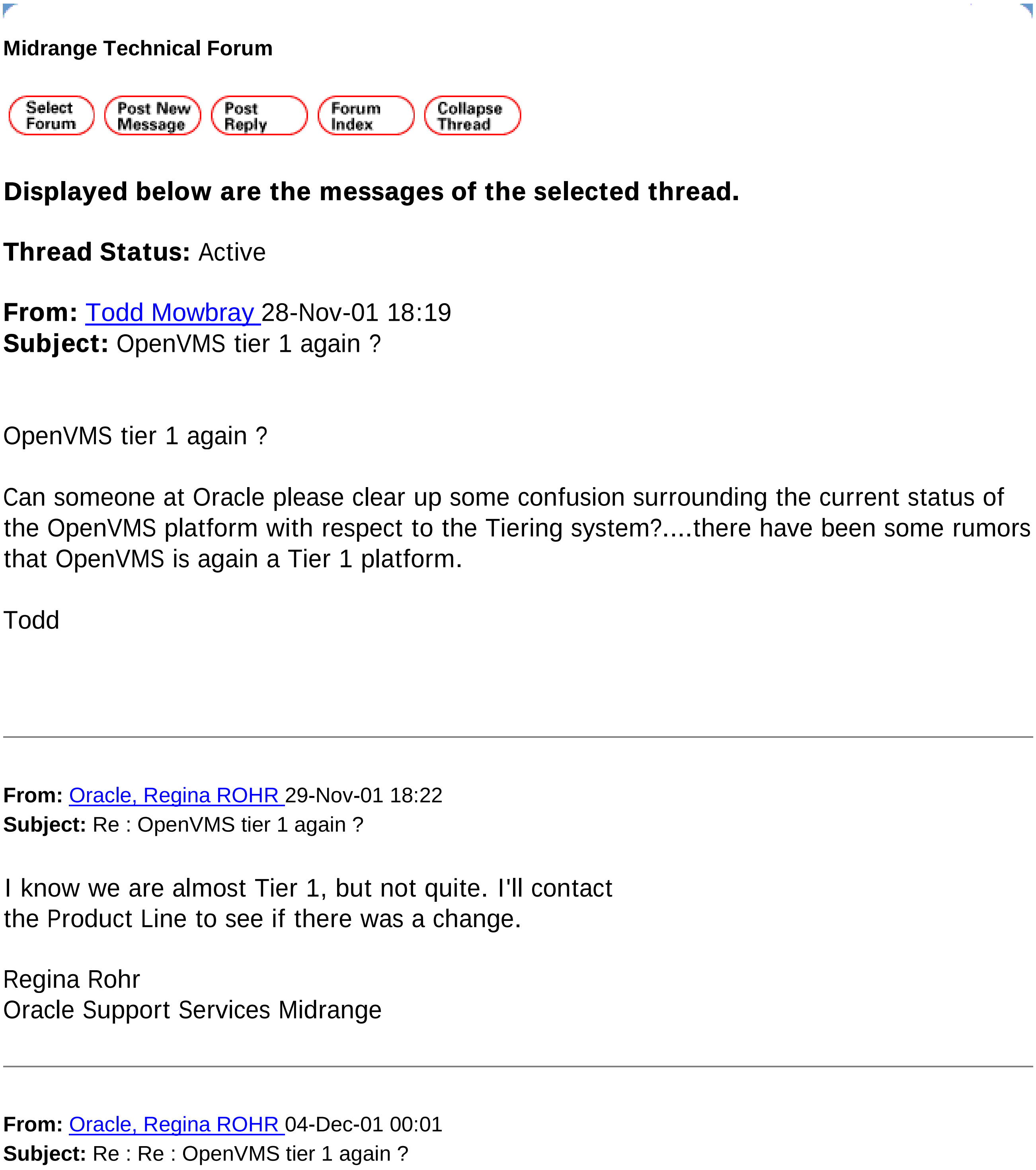
    Response:
    Part of the 3-5 year plan to migrate to NT servers

34. **Is there any documentation on the reasons (ROI / COS studies, Strategic planning reports, etc)?**

    Response:
    A report was written in August 2001 concerning OpenVMS as an operating system at Newfoundland Power.

APPENDIX B – OPENVMS TIER-2 RELATIONSHIP WITH ORACLE

The following Technical Assistance Request (TAR) confirms the Tier-2 relationship that OpenVMS has with Oracle. The TAR program allows customers to formally request assistance in solving product related problems, obtain software fixes, and get answers to questions concerning Oracle's line of products.



Midrange Technical Forum

Displayed below are the messages of the selected thread.

Thread Status: Active

From: Todd Mowbray 28-Nov-01 18:19
Subject: OpenVMS tier 1 again ?

OpenVMS tier 1 again ?

Can someone at Oracle please clear up some confusion surrounding the current status of the OpenVMS platform with respect to the Tiering system?....there have been some rumors that OpenVMS is again a Tier 1 platform.

Todd

From: Oracle, Regina ROHR 29-Nov-01 18:22
Subject: Re : OpenVMS tier 1 again ?

I know we are almost Tier 1, but not quite. I'll contact
the Product Line to see if there was a change.

Regina Rohr
Oracle Support Services Midrange

From: Oracle, Regina ROHR 04-Dec-01 00:01
Subject: Re : Re : OpenVMS tier 1 again ?

We are not tier 1, but we are one of the 9 strategic platforms.

Means we are not having everything. Like for instance iAS is not
available on OpenVMS.

So, no tier 1 but close.

Hope this helps,

Regina Rohr
Oracle Support Services Midrange

From: Todd Mowbray 07-Dec-01 21:12
Subject: Re : OpenVMS tier 1 again ?

I was hoping that this would mean increased focus on providing timely corrections to bugs that have affected other platforms, but seem to take a long time to get resolved on port 89 (OpenVMS).

From: Oracle, Regina ROHR 12-Dec-01 16:21
Subject: Re : Re : OpenVMS tier 1 again ?

What are the Tar numbers and bug numbers? If no customer
reports the error we do not get an automatic backport to OpenVMS
(nor any other platform, unless it is a security patch), it is per request only.

Thanks

Regina Rohr
Oracle Support Services Midrange

From: Todd Mowbray 18-Dec-01 15:56
Subject: Re : OpenVMS tier 1 again ?

Nothing specific, just a commentary on resolution time for say mts and connection performance problems, that seem to get resolved quicker on other ports.

Todd

Courtesy of Oracle Corp.

APPENDIX C – ORACLE 8.1.6 DESUPPORT NOTICE

Oracle Corporation
Product Obsolescence Desupport Notice

Product Details:

Product:	Oracle Server - Client, Enterprise Edition, Parallel Server, Personal Edition, RAC & Standard Edition
Product Version(s):	8.1.6 (8i)

Platform(s) Details:

Platform(s):	Platform Version(s):
ALL Platforms	ALL

Desupport End Dates:

Error Correction Support (ECS):	31-OCT-2001
Extended Assistance Support (EAS):	31-OCT-2004

Product Obsolescence / Desupport Information:

Oracle Corporation announces the end of Error Correction Support for **Oracle Server - Client, Enterprise Edition, Parallel Server, Personal Edition, RAC & Standard Edition version(s) 8.1.6 (8i)** on the following platform(s): **ALL Platforms,** effective **31-OCT-2001**.

Oracle Corporation recommends customers upgrade/migrate to the following as soon as possible to maintain the highest level of support: Oracle Server - Client, Enterprise Edition, Personal Edition & Standard Edition/Workgroup Server 8.1.7 (8i) on any Oracle certified platform.

EAS will be provided until **31-OCT-2004**, if the customer has a current support contract in place.

EAS **includes** the following:

Telephone and Electronic support, consisting of:

EAS does **NOT include** the following:

- Error Correction Support (ECS) - No new bug fixes
- Backporting of fixes

- Answers to customers' questions
- Assistance with migration plans to a supported platform and/or product
- Workarounds, where possible
- Certification with supported products, newer operating system versions or new compilers
- Escalation support, response time adherence and skill availability

Customer Action:

To upgrade/migrate, U.S. customers must contact Client Relations at the following: (NOTE: Non-U.S. customers must contact their Oracle Local Support Center (LSC).)

West: (719) 785-7600
Central & Mountain: (719) 635-8900
East: (407) 240-8900
Toll-Free: 1-800-223-1711

Exceptions and/or Miscellaneous Information:

- **Compaq Tru64 UNIX AlphaServers Customers:** Compaq Tru64 UNIX AlphaServers containing Alpha CPUs prior to version EV56 will be desupported in conjunction with Oracle8i 8.1.6. Customers should migrate to Compaq Tru64 UNIX AlphaServers containing Alpha CPUs version EV56 or higher.
- **E-Business Suite Customers:** E-Business Suite customers (including EMEA E-Business Suite customers) running 11.5.5 and lower will remain supported until **01-JUN-2002**. Please see Certify via MetaLink for certification details.
- For both Oracle8i 8.1.6 customers and all E-Business Suite customers, **the end of EAS will be 31-OCT-2004**.
- EMS will **NOT** be offered for 8.1.6.
- **Novell NetWare Customers:**
  - The 8.1.6 end of ECS date for Novell NetWare customers will be **31- DEC-2001**. This is due to Oracle8i 8.1.7's certification on Novell NetWare.
  - The 8.1.6 end of EAS date for Novell NetWare customers will remain the same as all other platforms.

- *This desupport notice is addressed to the customer's contact currently on file with Oracle Corporation. (NOTE: If the contact information is not current, please email the current contact information and CSI# to OBSSUPP_US@oracle.com.)*
- *This document is for informational purposes only, and is intended to outline Oracle Corporation's current migration path. The information in this document is subject to change without notice at Oracle Corporation's discretion. In accordance with Oracle Corporation's current transfer policy, future*

releases of Oracle programs (migration paths) are provided to customers who have a valid support contract only.

- *Customers with a current support contract may also view the current desupport notice via Oracle MetaLink at http://metalink.oracle.com, under "Product LifeCycle" --> "Certifications" by each product group or under Doc ID: 123178.1.*

For further assistance, please email OBSSUPP_US@oracle.com. Last modified: 22-May-2002 10:11:41 (U.S. Pacific Time)

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Courtesy of Oracle Corp.

APPENDIX D – ORACLE SERVER EDITIONS COMPARISON CHART

Product Editions

Evaluating Databases? Start Here

Oracle9*i* Database is available in both Standard [More Info || Add to Cart] & Enterprise Editions [More Info || Add to Cart]. The following options extend the power of the Oracle database in secure data management, transaction processing and data warehousing.

Feature Summary	Standard	Enterprise	Option
High Availability			
Oracle Data Guard		✓	
Standby Database	✓	✓	
Oracle Fail Safe	✓	✓	
Transparent application failover		✓	
Oracle Real Application Clusters [More Info || Add to Cart]		✓	✓
Oracle Partitioning [More Info || Add to Cart]		✓	✓
Security			
Advanced Security Option [More Info || Add to Cart]		✓	✓
Oracle Label Security [More Info || Add to Cart]		✓	✓
Virtual Private Database		✓	
Fine grained auditing		✓	
Password management and proxy authentication	✓	✓	
Manageability			
Java, XML and Globalization support	✓	✓	
Oracle Enterprise Manager	✓	✓	
Oracle Change Management Pack		✓	✓
Oracle Diagnostics Pack		✓	✓

Oracle Tuning Pack		✓	✓
Oracle Management Pack for Oracle Applications		✓	✓
Oracle Management Pack for SAP R/3		✓	✓
Analytics and Data Warehousing			
Oracle OLAP [More Info || Add to Cart]		✓	✓
Oracle Data Mining [More Info || Add to Cart]		✓	✓
Optimizer statistics management	✓	✓	
Analytic functions	✓	✓	
Content Management			
Oracle Workflow	✓	✓	
Oracle Spatial [More Info || Add to Cart]		✓	✓
Dynamic Services	✓	✓	
Oracle Internet File System	✓	✓	
Ultra Search	✓	✓	
*inter*Media	✓	✓	
Oracle Text	✓	✓	

Courtesy of Oracle Corp.

APPENDIX E – WINDOWS AND UNIX OPERATING SYSTEMS DISCUSSION PAPER

SOURCE, XWAVE ISBU ENTERPRISE SERVER TEAM

Comparison of WinTel and UNIX Operating Systems for Enterprise Environments

Many companies are at a critical juncture in their IT infrastructure evolution. Existing applications have been supported successfully based on sound investments in Windows NT, Intel-based platforms. However, as the infrastructure continues to evolve and becomes more integrated with daily operations, environments will have to move from an 8/5, five days a week reliability, to a 24 hour, five days a week reliability, and eventually to a complete 7/24 environment. This has significant implications in the areas of availability, redundancy, and capacity planning to name a few. Companies must understand the benefits and risks associated with using a single environment (Windows NT/2000) versus a heterogeneous environment (Windows / UNIX) to accomplish its business goals. The benefits and risks associated with each platform are discussed below. To a great extent many of the benefits / risks of a UNIX-based infrastructure are inverse to those of a WinTel architecture.

WinTel

Benefits

Fundamentally, the primary driver for companies using a WinTel environment is cost. Intel-based hardware is less expensive than UNIX hardware due to the mass-market production capabilities of the industry. In addition, there is more flexibility in choice of hardware platforms as many vendors compete to provide similar equipment, resulting in a reduction in overall cost. From a straight cost perspective it is very difficult to justify moving away from an WinTel infrastructure. This does not, however take into consideration the Total Cost of Ownership (TCO) associated with running a complete WinTel environment.

A second benefit of using a WinTel environment comes from the size of the development market for software. WinTel is by far the most common platform available in the marketplace, and as such, software vendors are more likely to develop software first or only for the WinTel server type. As with hardware, this diversity and volume of software providers creates a stronger market for potential applications, resulting in a broader array of products and lower purchase price points.

Due to the nature of the WinTel architecture, which typically assigns a single application to a single server, there is less chance of creating single points of failure. That is, due to the “horizontal growth” architecture for a WinTel environment there is rarely a single server in the system that will cause a catastrophic failure of multiple systems. This is not true in the UNIX realm where, due to the power of the server, it is not uncommon to have a single server performing multiple functions.

Another benefit of the WinTel architecture comes from the implementation of Active Directory under a Windows 2000 network. While many corporations have not yet availed of this feature (but are in the planning stage), the move to Active Directory helps to consolidate administration of the network environment as it treats all network elements, such as printers, servers and users, as elements in a directory database. This significantly reduces the amount of administration time required in a larger network environment.

The WinTel environment comes from the integration of Web Services with operating system, which is another benefit of this platform. As Microsoft has continued to evolve the operating system, they have continually integrated more functionality and interoperability with web services. On a go forward basis, as more core operational applications become exposed to web interface requirements, this becomes easier to both implement and manage.

Finally, many companies have already created a significant internal skill set within the company to design, build and operate a WinTel environment. This level of investment cannot be overlooked in considering how future applications are deployed. Any deviation from this path must justify the increased cost associated with training or hiring new resources, along with the fragmentation of existing resource cycles currently focused on maintaining the internal environment.

Risks

At the core of the risks surrounding the WinTel environment is stability. Despite significant gains in this area, the WinTel architecture still has not reached the level of stability that UNIX has been at for a number of years. Despite the advances in High Availability (HA) Clustering technologies and automatic fail-over capabilities, a WinTel environment is still not designed, fundamentally, with stability in mind. This comes from the very nature of the market environment which takes any number of “mix and match” parts from various vendors (Intel chips, Seagate drives, etc.) and tries to create a single computing environment. No matter how critically this is reviewed, the performance and operation of one vendor’s version of a WinTel server will vary from another vendors, which indeed is why vendors try to differentiate themselves on various performance metrics. While hardware failures have declined significantly in the past few years, the majority of failures are caused by the way in which the Application interacts with the Operating System and the Hardware. This “three-legged stool” only requires one small deviation or failure to cause an interruption in service. The longer an application is run without being shut down and started up again on a server, the more likely it is that something will start to go wrong. While rebooting a server may be acceptable in an 8/5 environment, it wreaks havoc in a 7/24 environment.

A second risk associated with a WinTel environment is a cost/management risk. Due to the architecture of a WinTel infrastructure, horizontal expansion (adding more servers with each application) means more servers to manage. This is compounded when you try to bring this to a fully redundant, HA clustered infrastructure where you are buying multiples of servers for each application. This “server sprawl” characteristic is often the trigger point for companies starting to investigate alternative platforms and / or Total Cost of Ownership for their IT infrastructure.

Another risk associated with WinTel architecture comes from the application development cycle itself. As applications are moved into the core of operation functionality for companies there needs to be a certain level of comfort and stability in the operating system environment. The Windows environment is constantly changing with new release versions and complete overhauls of the operating system coming every year or two. Many companies are now just starting to figure out how to move to Windows 2000, and Microsoft is preparing to release Windows 2002. As such applications become tied to future Windows capability and functionality, which has implications for both go-forward implementation, and retroactive support.

Finally, but certainly not least important, is the issue of security. Overall, a WinTel environment tends to be less secure than UNIX for a number of reasons. First, because it is more prevalent (more desktops have Windows than UNIX as operating system), it is simply a larger target for subversive activities. Second, because the WinTel system is configured to “work out of the box” it is often over-provisioned from an application perspective. That is, it comes with additional drivers, options etc. that are never used and can pose unknown security risks. It is common for WinTel server to become increasingly stable and secure as more unnecessary software and drivers are removed from them.

Summary

The WinTel architecture is a low entry cost method to provision computing power to the enterprise. However as applications increase, both the size of the application and the number of applications, issues arise with the manageability, total cost of ownership and security of the environment. With these characteristics WinTel servers are generally used for e-mail / messaging services, web services, file services, print services, small to medium application services and small to medium database services.

UNIX

Benefits

The first and most cited benefit, of a UNIX infrastructure is stability. Overall, UNIX systems have been created to manage mission-critical application, and as such, the OS kernel has been minimized in order to create a more stable operating system. In addition, although all UNIX versions come from the same original source code (created by Bell Labs), each vendor has modified it to custom-fit its own hardware. As such SUN has created Solaris, IBM has created AIX, Compaq has created Tru64 UNIX, etc. Once again, while they are fundamentally from the same original UNIX kernel, each one has been tuned to the specific hardware. This results in an overall reduction in issues as compared to a WinTel environment as the “three-legged stool” has two of the legs combined (hardware and OS) to reduce potential conflicts. This is further reduced in complexity as most application vendors test and performance-tune their application with specific flavours of UNIX, such as SAP on Solaris or JDE on AIX. The result is a much more stable and robust environment, which is of key consideration for staging production applications.

The second benefit of a UNIX-based platform is vertical expansion. Unlike a WinTel environment that tends to expand horizontally (adding servers), a UNIX environment scales well vertically by allowing multiple applications, and even multiple virtual servers, to reside on a single infrastructure. This provides for reduction in space and power consumption, as well as creating fewer servers to manage. Moving from a WinTel environment to a UNIX environment is often associated with addressing server sprawl issues. The ability to multi-thread activities is core to the way UNIX was originally developed, and as such, it is performed natively on most UNIX platforms. Another result of this history is that workload management and management tools for UNIX platforms tend to be much more developed and tested in the UNIX world than are their counterparts in the WinTel space. The latest iterations of operating system software allow for advanced features such as dynamic reconfiguration and Domaining / LPARing to enable logical and physical separation of applications on the same server, much akin to the way in which a mainframe environment treats its various partitions.

Another benefit of a UNIX-based platform is its close integration with Internet applications. Historically UNIX has been closely integrated with the Internet, and even in a Microsoft dominated work most large web servers are still UNIX and/or Linux based. UNIX was founded on the concept of a networked environment (all UNIX machines come pre-configured with a native IP address) and as such is designed to work best in that configuration. On a go-forward basis as the Internet becomes more integrated into the daily operation of companies, this will become increasingly important.

Risks

As with the WinTel environment, there are also significant risks associated with a company moving into a UNIX-based environment. The primary risk lies in higher entry-level costs for hardware. On a cost-per-unit basis a UNIX environment costs significantly more than a WinTel environment due to fewer competitors, a smaller market and less demand. This price-point differential is a major barrier to many small and medium sized businesses deploying a UNIX-based infrastructure.

A second drawback associated with UNIX is the proprietary nature of hardware and operating systems. As noted in the benefits section, each OS is tuned to specific hardware, which results in a much more stable environment. The downside, however, is that once a company has committed to a platform, it becomes much more difficult to deviate and hence, the company tends to be tied to a single vendor.

It is important to pause at this point to briefly mention Linux. Linux is a non-hardware specific version of UNIX that has gained much popularity and press in the past several years. It is a true UNIX operating system whose kernel can be recompiled on almost any machine. However, despite the hype, Linux is not ready for deploying large-scale vendor applications like ERP, or Financials at this time.

The final risks associated with a UNIX-based environment are skill sets. UNIX is not an “out of the box” type of operating system. Unlike a WinTel server, a UNIX server comes with nothing loaded on it, and it works only as you add specific drivers, applications, etc. While it is completely configurable, it requires a significant amount of experience and/or training to operate effectively. This is another significant barrier to using UNIX within many company environments since, to adopt a UNIX platform, would require hiring and/or retraining resources.

Summary

UNIX is a very robust, scaleable and flexible environment that is commonly used in medium to large organizations that require continuous availability of mission-critical applications and data. UNIX environments are most commonly used for e-mail / messaging services, web services, proxy services, DNS services, firewall services, small to large application services and small to large database services.

APPENDIX F – MIGRATION OF ALL EXISTING OPENVMS APPLICATIONS

This appendix contains high-level server configurations to replace all existing OpenVMS applications at Newfoundland Power.

The migration to a Windows environment would result in a change in how the existing applications and the databases are structured. The application and database services would be separated onto their own servers. Four Compaq DL380s would host the production applications while a larger Compaq DL580 would contain the Oracle databases. The creation of a second environment would host the development effort and at the same time act as a disaster recovery server infrastructure. This configuration maximizes the utilization of the disaster recovery servers while at the same time reduces the number of servers required to support.

The production servers would be housed at Duffy place. This places the CSS application close to the majority of users of the production system.

The table below details the server configurations for the production Windows environment. Costs include acquisition / product cost only.

Server Configurations for the Production Windows Environment			
Component	Function	Configuration	Cost
Production Database Server	Database server for production applications	Compaq DL580 2 X1600-1MB MHz CPUs 6 GB RAM 4 X 72.8 GB Disks Oracle licensing	$80,600
Production Application Server 1	Application server for • CSS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Runtime software	$34,000
Production Application Server 2	Application server for • PCLS • JUS • SLMS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Runtime software	$34,000
Production Application Server 3	Application server for • MES • SRS • PES • TLIS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Runtime software	$34,000
Production Application Server 4	Application server for • SWITCH • FASBE • HRIS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Runtime software	$34,000
Storage Area Network	SAN for production servers	HP (Compaq) SAN	$130,000

Server Configurations for the Production Windows Environment			
Component	Function	Configuration	Cost
Server Rack	Rack for production servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for production servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$363,600.00

Table 26 - Production Windows Environment for all existing OpenVMS applications

The development servers would be housed at the Kenmount Road office. The servers have the same hardware and software configurations as the production servers in order to provide the same performance for users in the event of a production server failure.

Server Configurations for the Development Windows Environment			
Component	Function	Configuration	Cost
Development Database Server	Database server for development applications	Compaq DL580 2 X1600-1MB MHz CPUs 6 GB RAM 4 X 72.8 GB Disks Oracle licensing	$47,900
Development Application Server 1	Application server for • CSS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Compiler and Runtime software	$54,500
Development Application Server 2	Application server for • PCLS • JUS • SLMS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Compiler and Runtime software	$54,500
Development Application Server 3	Application server for • MES • SRS • PES • TLIS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Compiler and Runtime software	$54,500
Development Application Server 4	Application server for • SWITCH • FASBE • HRIS	Compaq DL380 2 X1400-1MB MHz CPUs 2 GB RAM 2 X 36.4 GB Disks Compiler and Runtime software	$54,500

Server Configurations for the Development Windows Environment			
Component	Function	Configuration	Cost
Storage Area Network	SAN for development servers	HP (Compaq) SAN	$130,000
Server Rack	Rack for development servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for development servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$412,900.00

Table 27 - Development Windows Environment for all existing OpenVMS applications

As in the case of a migration to Windows, the UNIX production servers would be housed at Duffy place. This places the CSS application close to the majority of users of the production system.

The table below details the server configurations for the production UNIX environment. Costs include acquisition / product cost only.

Server Configurations for the Production UNIX Environment			
Component	Function	Configuration	Cost
Production Database Server	Database server for production applications	Sun SunFire V480 2 X 900 MHz CPUs 6 GB RAM 2 X 36GB Disks	$114,000
Production Application Server	Application server for • CSS • PCLS • JUS • SLMS • MES • SRS • SWITCH • FASBE • HRIS • PES • TLIS	Sun SunFire V480 2 X 900 MHz CPUs 6 GB RAM 2 X 36GB Disks	$56,600
Storage Area Network	SAN for production servers	HP (Compaq) SAN	$130,000
Server Rack	Rack for production servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for production servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$317,600.00

Table 28 - Production UNIX Environment for all existing OpenVMS applications

The UNIX development servers would be housed at the Kenmount Road office. Like the Windows alternative, the servers have the same hardware and software configurations as the production servers in order to provide the same performance for users in the event of a production server failure.

Server Configurations for the Development UNIX Environment			
Component	Function	Configuration	Cost
Development Database Server	Database server for development applications	Sun SunFire V480 2 X 900 MHz CPUs 6 GB RAM 2 X 36GB Disks	$61,400
Development Application Server	Application server for • CSS • PCLS • JUS • SLMS • MES • SRS • SWITCH • FASBE • HRIS • PES • TLIS	Sun SunFire V480 2 X 900 MHz CPUs 6 GB RAM 2 X 36GB Disks	$56,600
Storage Area Network	SAN for development servers	HP (Compaq) SAN	$130,000
Server Rack	Rack for development servers	Compaq 245161-B21 Rack 10642	$13,000
Communications Switch	Switch for development servers	Cisco Catalyst 3524	$4,000
		Total (excluding tax)	$265,000.00

Table 29 - Development UNIX Environment for all existing OpenVMS applications

Appendix H - Gartner Research Note: The Case for OpenVMS: Should You Migrate?

External

Decision Framework, DF-18-0559
G. Weiss

Research Note
15 October 2002

The Case for OpenVMS: Should You Migrate?

OpenVMS users must consider the options and planning criteria for staying with, or leaving, OpenVMS.

Core Topic
Hardware Platforms: Server Platforms

Key Issue
How will centralized and distributed servers evolve during the next five years?

Strategic Planning Assumptions
Fewer than 10 percent of OpenVMS users will migrate from Alpha to Itanium by 2006 (0.7 probability).

Fifty-five percent of users will migrate from Alpha OpenVMS to a competitive vendor platform (Unix or Windows Server) by 2006 (0.7 probability); 20 percent will migrate to an HP merged Unix or Windows Server environment by 2006 (0.7 probability); 25 percent of OpenVMS users will remain with OpenVMS beyond 2006 (0.7 probability).

We apply our framework for evaluating the planning process of a server migration (see "How to Plan a Server Migration Strategy") to the issues of how and when users should consider a migration from OpenVMS.

Is the application support by third parties shrinking?

OpenVMS is definitely a shrinking market opportunity for independent software vendors (ISVs). Many of the original third-party ISVs are out of the OpenVMS market or have proclaimed their last releases supported on OpenVMS, and we expect continued attrition. Thus, users with strong third-party dependency must monitor their ISVs and be prepared with an alternative platform strategy in advance of ISV departures. With Hewlett-Packard's (HP's) stated intention to move the OpenVMS environment to Itanium, users should request clear indications that ISVs will also move and support their applications on Itanium. If the preponderance of ISVs fail to support Itanium, the intended move of OpenVMS will encounter the chief obstacle to its viability in application support.

How much custom code has been developed?

For the 50 percent or so remaining OpenVMS users running custom code, these IS organizations have the flexibility to await the outcome of HP's migration to Itanium. However, the IS organization should also be ready to assess the costs of migrating the existing code under OpenVMS or selecting another platform and operating system (OS) with third-party applications or conversion of code. If the code remains under OpenVMS and is portable enough to recompile and link, the IS organization should ensure that the code is well-documented in case the original developers depart before Itanium production systems are deployed. Even with such flexibility, the IS organization should restrain further development. Loss of the people who developed the code and poor documentation may mean starting from scratch or switching to third-party packages that may not be available for OpenVMS. At worst, HP intends to provide a binary translation tool at a likely trade-off in performance.

What is the level of in-house administration and technical skills?

If OpenVMS skills become increasingly difficult to find or keep, then it's very likely that the IS organization will pay increasingly higher costs for the maintenance of OpenVMS over time. We believe that users will inevitably face this difficulty and that HP will not be able to assure the OpenVMS community of the size and distribution of technical and administrative skills. Most of the "new IT skills" emerging in the market will be focused on Linux, Microsoft .NET, deployment and provisioning, and advanced database administration, while proprietary environments will continue to suffer skill attrition. Users can help soften the impact if OpenVMS programs move to Java and C++ as the common development and program environment.

What is the degree of interoperability and systems integration with other enterprise systems?

The remaining loyalists have mostly used OpenVMS clustering and high-availability solutions as a testament to its high reliability and scaling. These IS organizations' reluctance to move from OpenVMS is partly from the fear that an alternative OS, such as Windows or Unix, will not provide comparable reliability and ease of use. These OpenVMS systems are operationally viable, but organically (growth in applications) static. Therefore, they should be positioned as high value to operations, low value to application expansion. Despite some of the protocols offered for interoperability (TCP/IP, COM for OpenVMS, Pathworks), we remain skeptical of OpenVMS playing roles as peer nodes in Windows and Unix networks.

What is the vendor's road map for the platform?

HP has decided to continue an OpenVMS road map entailing the movement of a good deal of the system code to Itanium. According to HP, the reason is that the Itanium migration is considerably simpler and easier to manage than the VAX-to-Alpha migration, its estimated internal costs will be reasonable (estimated in the $40 million range), and the current OpenVMS/Alpha revenue stream is profitable. However, the real issue is whether the program will translate into user benefits. HP must prove that the costs of migration to users will provide longer-term returns than a migration to an alternative platform. IS organizations therefore must assess the following:

1. How much of the code can move intact with compatibility maintained on Itanium 2?
2. What parts of the system code and layered software will continue to be supported vs. that designated "end of life"?
3. How well will the code perform on the designated new Itanium platforms?

These questions will remain indecisive until completion of the OpenVMS port and the delivery of production platforms on which users can run test profiles. Users will probably not have definitive answers before 2005, but HP intends to report on milestones of its posted road maps on its Web site.

What are the vendor's technical support resources?

Although HP may have the OpenVMS installed base's interest at heart, it will be exceedingly difficult to maintain a core of well-trained specialists worldwide that can service all of the OpenVMS accounts with mission-critical responsiveness. Simply put, IT careers are made on growth platforms as opposed to legacies considered remnants of a bygone era, regardless of the technology's superiority.

What is the rate of advancement and functional improvements for the platform?

As a leading indicator, users must trust HP and its partners to provide a continual stream of enhancements. If it cannot, or is not willing to provide the investment and marketing effort, OpenVMS will lack traction and strategic value. Although HP claims 400,000 systems and a continuing profitable revenue stream of $2 billion as justification for continued support, HP must nevertheless prove that the OS fits well into the evolving commodity nature of the hardware market. Systems supporting OpenVMS must be modular, be flexible and support a variety of software solutions to compete effectively. OpenVMS users should not expect priority responsiveness with the other merger details, road maps and costs vying for attention, with the exception perhaps of Galaxy, a partitioning scheme for AlphaServers that must be moved to Itanium.

What are the suggested targets for an upgrade?

Currently, HP's strategy consists of upgrades of HP-UX platforms such as Superdome to Itanium and the introduction of two-way and four-way Itanium 2 systems (announced 8 July 2002). Users must be apprised of the complete system road map encompassing the replacement of the Alpha GS series, including performance data and test suites. AlphaServer systems are an alternate choice, with a chip upgrade due in 2004, but with a high probability of no further shipments after 2006 and cessation of support by 2011.

What other vendor systems directly or indirectly compete for market attention?

HP intends to continue to support NonStop systems, ship AlphaServers to about 2006 (with continued support of Tru64 but without further enhancements), ship PA-RISC systems with HP-UX, oversee user migrations from PA-RISC to Itanium and continue server marketing programs for Windows (ProLiant family), blades and Linux. Thus, OpenVMS must be evaluated in the context of a broad product portfolio and its effectiveness to contribute to HP's bottom line. So far, HP is suggesting that OpenVMS is a strategic installed base. However, we believe that the true test will be speed of execution in moving users to Itanium. Inordinate delays would have an atrophying effect and could divert resources and marketing attention to the winning platforms.

How profitable, under scrutiny, is the revenue stream for the platform?

HP maintains that OpenVMS business is profitable and maintenance revenue is good enough to sustain a business of continuing support for OpenVMS. Users should evaluate their own support expenses. If the platform is operationally self-sustaining at minimum cost, there should be no urgency to migrate to other platforms or operating environments. HP has indicated that it intends to create a Unix-like OpenVMS environment and attract Unix developers and applications to the platform. We would advise users not to be lulled by this. Such programs have had minimal success in the past (for example, IBM's attempt on the mainframe with Unix Systems Services) and represent a contrarian view of building more Unix variants than the market seeks in this era of consolidation.

Has vendor management made a firm commitment to the platform's viability?

We have been pleasantly surprised by HP and Compaq's serious endeavor to enhance the viability of OpenVMS with a detailed road map. Had there been a muted response after the merger, we would have declared an earlier end of life. Such an effort is worth recognition but not a passport to sustained long-term viability. OpenVMS users may feel more breathing room, but they must still remain alert to the road map's progress.

What will be the maximum period the user/organization can remain on the platform before organizational ineffectiveness sets in?

Eventually, because of limited development, infrequent refreshment of the technology, and a lack of human resources or application choices, an organizational IT program on OpenVMS will atrophy on the platform. As an outside target, OpenVMS could continue to survive through 2010, but the relevant issue is IT effectiveness: will it meld with the strategic directions and applications of the enterprise, or will it remain an island of computing, doing its limited jobs well but outside the organic growth of IT. HP is hoping that enabling Java development, Web services and selected ISVs such as BEA Systems and Oracle will make OpenVMS as vital as other operating environments. However, such endorsements and tools are only as effective as the speed with which enhancements are delivered to the platform. In an era of consolidation, Oracle and SAP are bent on a course of consolidating to a few Unix variants with hopes that Linux becomes the standard environment. Then, fewer ports will need to be maintained, reducing the ISV's internal resources and costs.

How much will a migration cost?

Third-party systems integrators and specialists in converting code and system software should help users assess the costs in migrating to HP's Itanium on OpenVMS vs. targeting another OS and platform. Costs could range from a low end of $100,000 (three-month project) to a high end of $3 million (eight months), based on the type and amount of code (for example, assembly code, 3GL, 4GL), retraining and redeployment. Among third parties in this market are Sector7 and TKM Digital (formerly Digital India). HP offers free assessments and workshops to minimize upfront costs, but the actual migration costs must still be borne by the user.

Bottom Line: The issue for most users is not whether to migrate, but when. We believe OpenVMS is not a sustainable strategy other than for specific and short-term tactical needs or budget constraints. If users intend to see the OpenVMS transition through to Itanium, then we recommend that they negotiate for service credits and loaners to minimize cost burdens during the transition. Such credits can come in the form of preliminary migration assessments, performance analysis, compatibility certification and loaners for pilots. If HP cannot provide specific timetables and products for the transition by mid-2003, users should have, and resort to, a contingency plan to an alternative platform. For the small, but statistically significant, number of governmental and defense users of OpenVMS with much longer

Acronym Key

HP	Hewlett-Packard
ISV	Independent software vendor
OS	Operating system

support expectations and less dependence on ISVs, these users should remain with OpenVMS and demand support from HP even beyond HP's stated end of support around 2011.

Appendix I - HP OpenVMS Rolling Roadmaps External

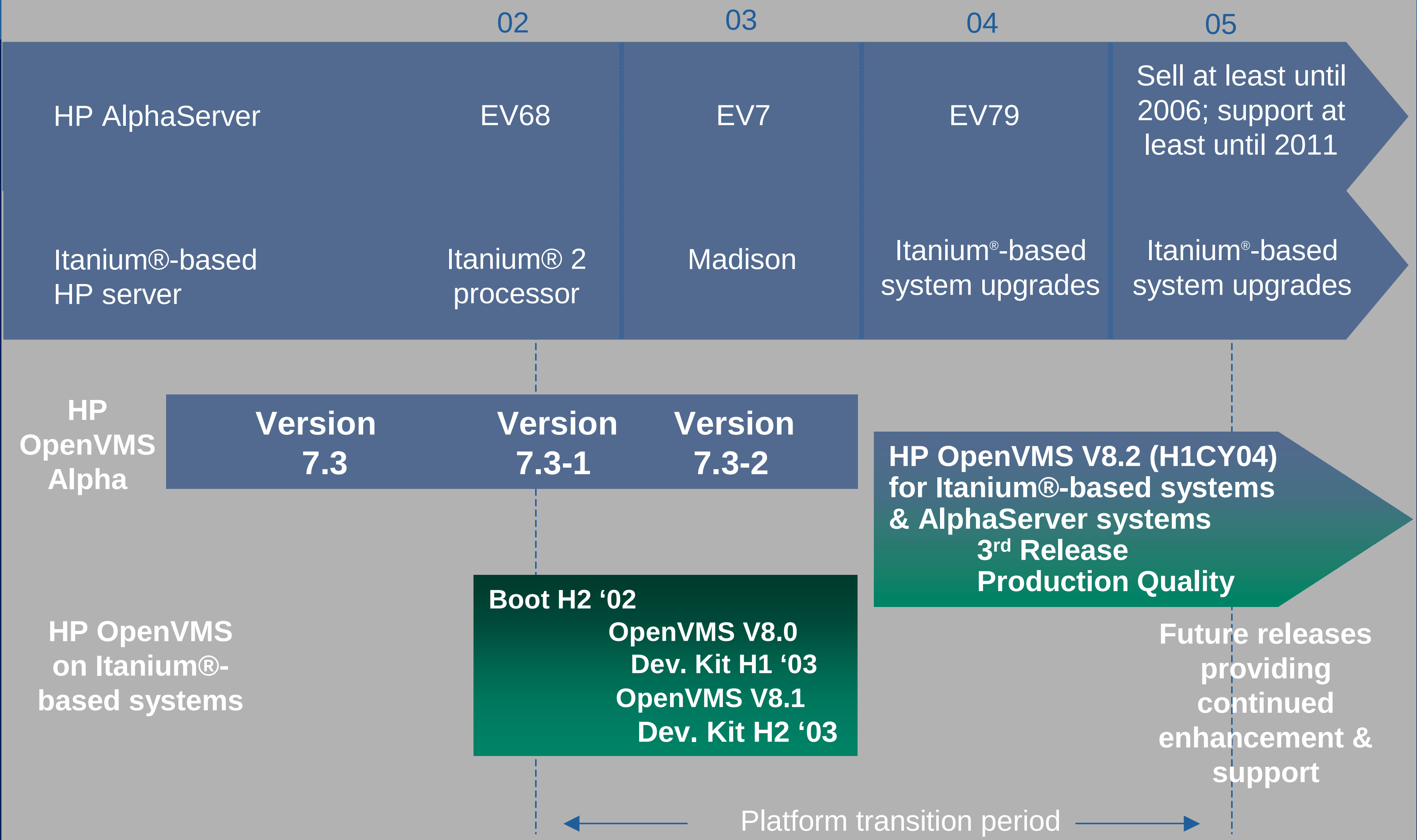
hp OpenVMS Rolling Roadmaps

HP makes no warranties regarding the accuracy of any information disclosed. *This time sensitive information is provided to facilitate customer planning processes.* HP does not warrant or represent that it will introduce any product or feature to which this information may relate.

These roadmaps are updated every two to three months.

hp OpenVMS
Itanium®-based Architecture Porting Roadmaps

hp OpenVMS roadmap



	02	03	04	05
HP AlphaServer	EV68	EV7	EV79	Sell at least until 2006; support at least until 2011
Itanium®-based HP server	Itanium® 2 processor	Madison	Itanium®-based system upgrades	Itanium®-based system upgrades

HP OpenVMS Alpha

Version 7.3

Version 7.3-1

Version 7.3-2

HP OpenVMS on Itanium®-based systems

Boot H2 '02
OpenVMS V8.0 Dev. Kit H1 '03
OpenVMS V8.1 Dev. Kit H2 '03

HP OpenVMS V8.2 (H1CY04) for Itanium®-based systems & AlphaServer systems
3rd Release
Production Quality

Future releases providing continued enhancement & support

← Platform transition period →

hp OpenVMS Itanium®-based Systems Roadmap

H1 03 **H2 03** **H1 04** **H2 04**

1st Boot occurs/Internal Kit

★

First Ship

H1 03: OpenVMS V8.0 “Mako”
Audience: Key ISVs, Partners, Early Adopters
OpenVMS Itanium Operating System, Monitor Utility
Networks: DECnet Phase IV, TCP/IP
Development Tools: Cross Linker, Librarian
Cross Compilers: C, C++, BLISS, FORTRAN, IMACRO

★★

H2 03: OpenVMS V8.1 “Jaws”
Audience: Key ISVs, Partners, Early Adopters
Limited cluster functionality (4 nodes)

Native Compilers: C, C++, BLISS, FORTRAN, IMACRO, Pascal, BASIC, COBOL

Additional Language Support: JAVA

Additional Layered Products…Networks, Data Serving, Security, eBusiness Integration, Application Development

Internal releases

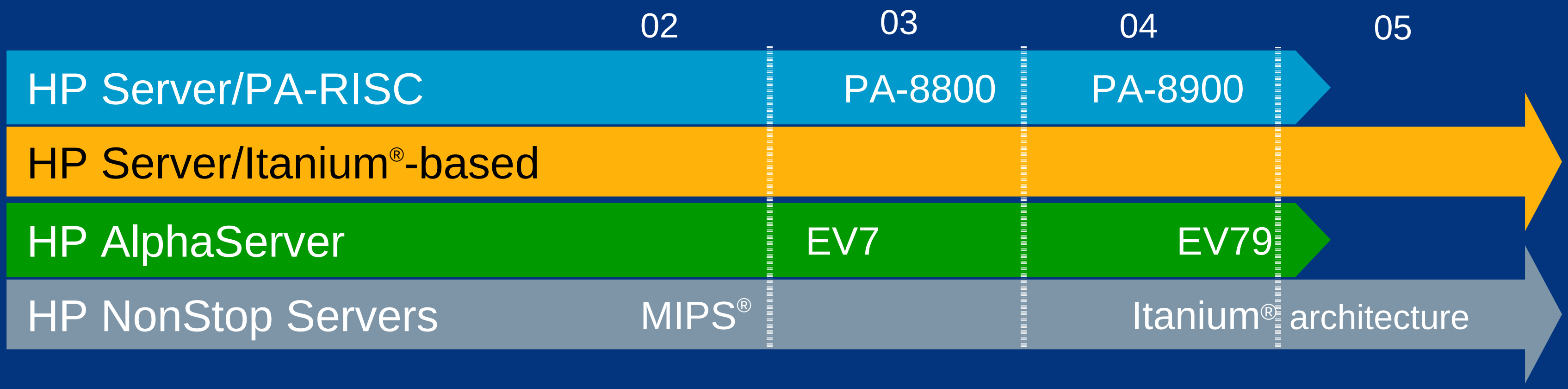
External releases

★★★

Production Quality → **OpenVMS V8.2**

hp Systems Roadmaps

BCS leadership system roadmaps



02 03 04 05

HP Server/PA-RISC PA-8800 PA-8900

HP Server/Itanium®-based

HP AlphaServer EV7 EV79

HP NonStop Servers MIPS® Itanium® architecture

HP Server/PA-RISC	deliver leading PA-RISC servers based on existing roadmaps
HP Server/Itanium®-based	provide compatibility with PA-RISC servers and support HP-UX, Linux®, Windows®/64, and OpenVMS
HP AlphaServer	deliver on published roadmap, planned sales at least till 2006, with support at least until 2011
HP NonStop Servers	published roadmaps remain unchanged

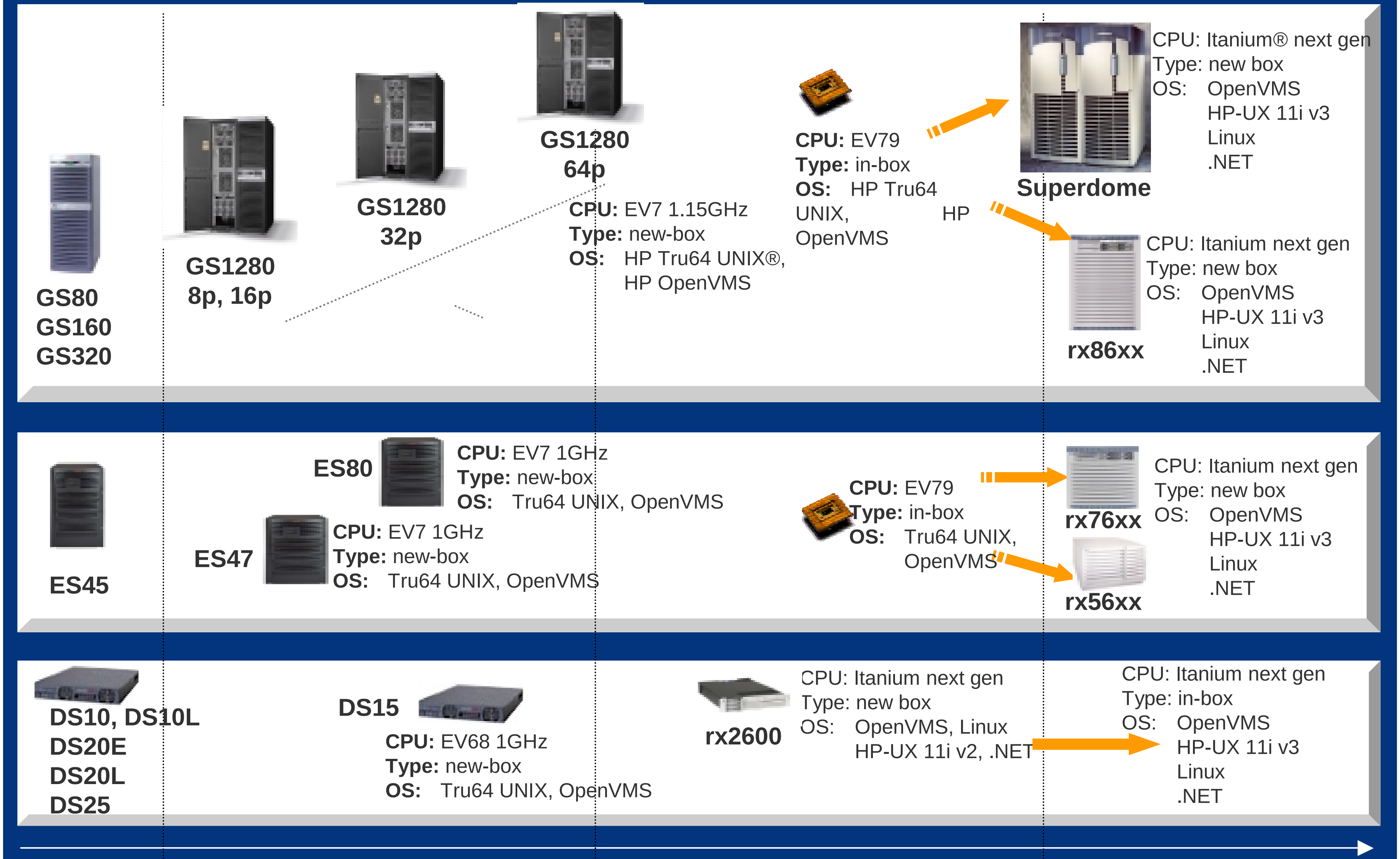
no change to existing server roadmap commitments

hp AlphaServer roadmap

	02	03	04	05
HP AlphaServer	HP AlphaServer GS EV68 (1-32p)	EV7 (8-64p)	EV79	
	HP AlphaServer ES EV68 (1-4p)	EV7 (2-8p)	EV79	ongoing sales and support
	HP AlphaServer DS EV68 (1-2p)	DS15		

- deliver HP AlphaServer systems according to published roadmap, including EV7 and EV79-based systems
- Sales at least until 2006, with support at least until 2011
- protect customer investment through “best-in-class” migration program
- flexible upgrade paths, allowing customers to move when ready

hp AlphaServer evolution



GS80
GS160
GS320

GS1280
8p, 16p

GS1280
32p

GS1280
64p

CPU: EV7 1.15GHz
Type: new-box
OS: HP Tru64 UNIX®, HP OpenVMS

CPU: EV79
Type: in-box
OS: HP Tru64 UNIX, HP OpenVMS

Superdome

CPU: Itanium® next gen
Type: new box
OS: OpenVMS
HP-UX 11i v3
Linux
.NET

rx86xx

CPU: Itanium next gen
Type: new box
OS: OpenVMS
HP-UX 11i v3
Linux
.NET

ES45

ES80

CPU: EV7 1GHz
Type: new-box
OS: Tru64 UNIX, OpenVMS

ES47

CPU: EV7 1GHz
Type: new-box
OS: Tru64 UNIX, OpenVMS

CPU: EV79
Type: in-box
OS: Tru64 UNIX, OpenVMS

rx76xx

rx56xx

CPU: Itanium next gen
Type: new box
OS: OpenVMS
HP-UX 11i v3
Linux
.NET

DS10, DS10L
DS20E
DS20L
DS25

DS15

CPU: EV68 1GHz
Type: new-box
OS: Tru64 UNIX, OpenVMS

rx2600

CPU: Itanium next gen
Type: new box
OS: OpenVMS, Linux
HP-UX 11i v2, .NET

CPU: Itanium next gen
Type: in-box
OS: OpenVMS
HP-UX 11i v3
Linux
.NET

subject to change without notice – current as of October 1, 2002

invent

hp OpenVMS Alpha, VAX and Itanium®-based operating system

- Releases, COE
- UNIX Portability
- Clusters
- Storage
- LAN
- Security

hp OpenVMS Operating System Roadmap

2003

2004

2005

2006

OpenVMS Alpha V7.3-2 (Opal)
Minor Release
FRS: Q4CY2003

- Ongoing EV7 platform support
- Performance Enhancements
- Unix® Portability Standards
- Availability enhancements
- DECwindows XIIR6 support

OpenVMS V8.2 (Topaz)
Major Feature Release
Platforms: Itanium®-based , Alpha & VAX
FRS: H12004

- Performance
- Security
- Storage
- Standards
- Alpha Compatibility with OpenVMS Itanium®
- Clusters

OpenVMS V8.x
New Feature Release
Platforms: Alpha and Itanium®-based
FRS: H12005

- Performance
- Security
- Storage
- Standards

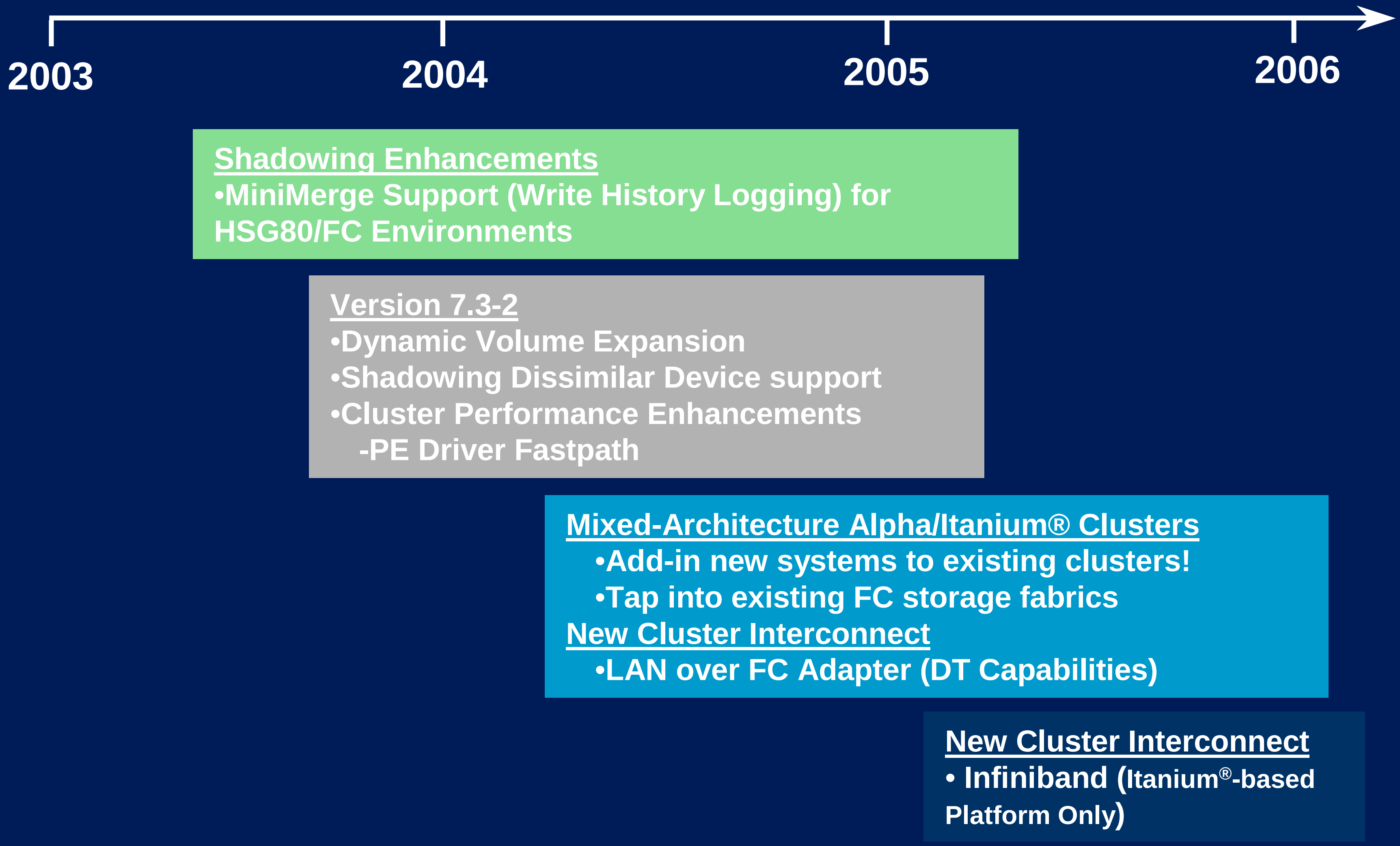
OpenVMS V8 on Itanium®-based architecture
Initial Release (V8.0): H1CY03
Update Release (V8.1): H2CY03

HW Update to V7.3-1
V7.3-1 plus HW remedial kit
FRS: January 2003

- EV7 New System Support

OpenVMS releases

OpenVMS Cluster Roadmap



Shadowing Enhancements

- MiniMerge Support (Write History Logging) for HSG80/FC Environments

Version 7.3-2

- Dynamic Volume Expansion
- Shadowing Dissimilar Device support
- Cluster Performance Enhancements
  - PE Driver Fastpath

Mixed-Architecture Alpha/Itanium® Clusters

- Add-in new systems to existing clusters!
- Tap into existing FC storage fabrics

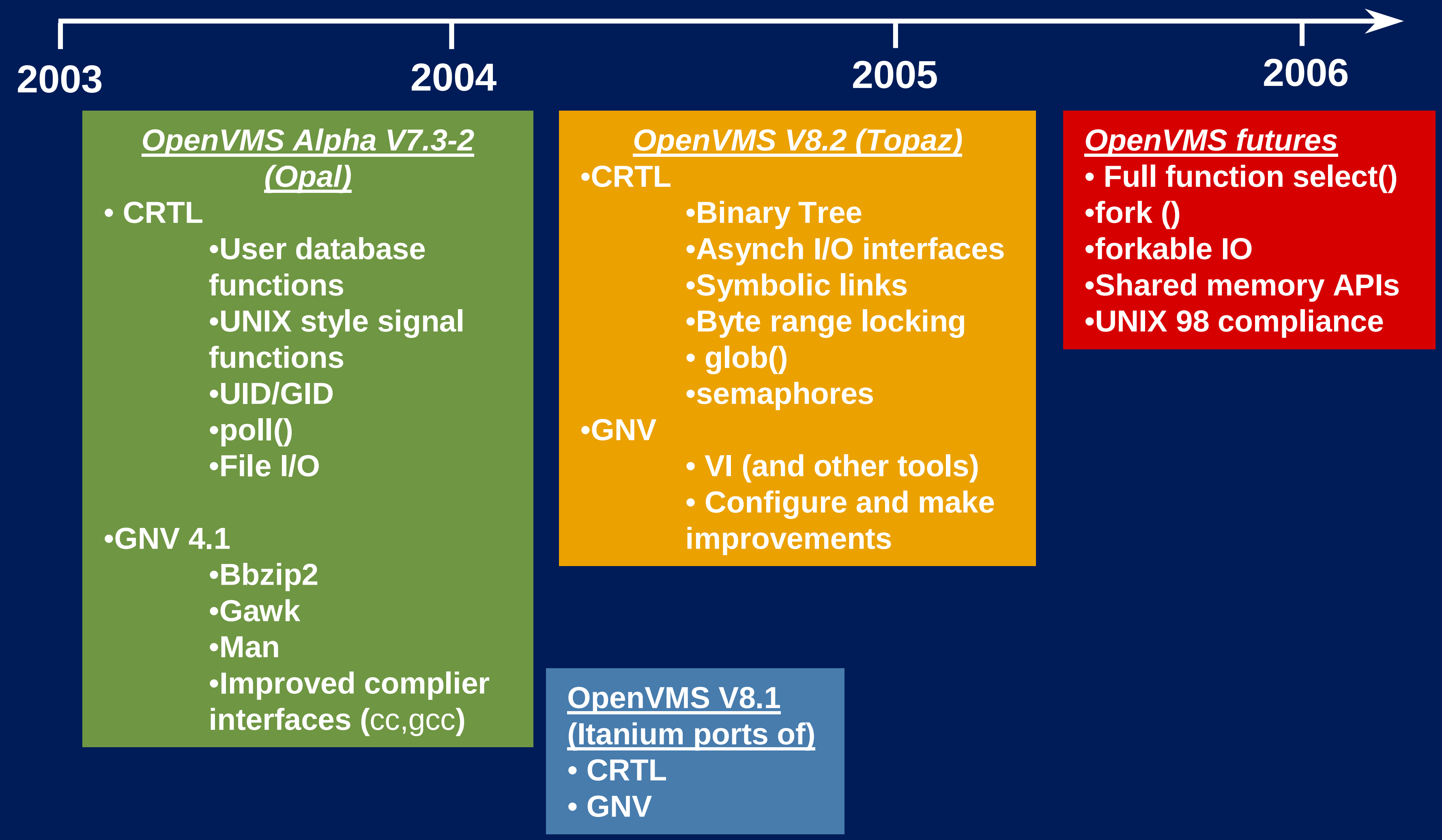
New Cluster Interconnect

- LAN over FC Adapter (DT Capabilities)

New Cluster Interconnect

- Infiniband (Itanium®-based Platform Only)

Unix Portability Roadmap



2003 2004 2005 2006

OpenVMS Alpha V7.3-2 (Opal)

- **CRTL**
  - **User database functions**
  - **UNIX style signal functions**
  - **UID/GID**
  - **poll()**
  - **File I/O**

- **GNV 4.1**
  - **Bbzip2**
  - **Gawk**
  - **Man**
  - **Improved complier interfaces** (cc,gcc)

OpenVMS V8.2 (Topaz)

- **CRTL**
  - **Binary Tree**
  - **Asynch I/O interfaces**
  - **Symbolic links**
  - **Byte range locking**
  - **glob()**
  - **semaphores**
- **GNV**
  - **VI (and other tools)**
  - **Configure and make improvements**

OpenVMS futures

- **Full function select()**
- **fork ()**
- **forkable IO**
- **Shared memory APIs**
- **UNIX 98 compliance**

OpenVMS V8.1 (Itanium ports of)

- **CRTL**
- **GNV**

OpenVMS Storage HW Roadmap

2003 2004 2005 2006

Lower cost FC - MSA1000 (Q1 2003)
- **2-node support Arbitrated Loop at FRS**
- **Switched Support (using existing external Switch)**
- **Imbedded Switch early Q2 2003**

Virtualization Support
- **SV3000 Investigation**
- **VersaStor HBA H1 2004**

Continued EVA and Device Support
- **Support of new Storage EVA solutions**
- **Support new storage Tape and Disk solutions (SDLT, Ultrium 2, NSR, etc)**

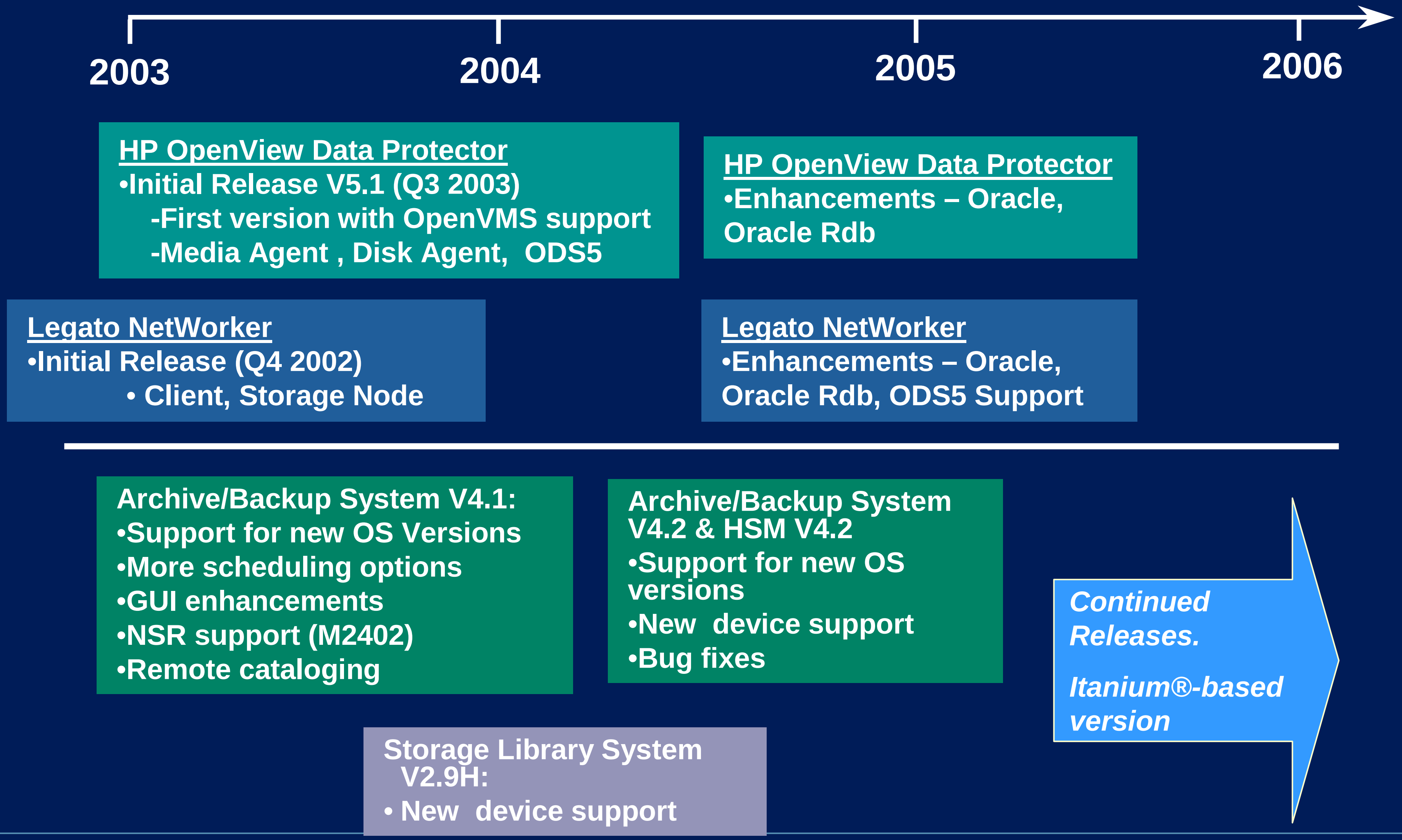
OpenVMS Itanium® Storage Support (H1 2004)
- **FC support to connect into existing SANs**
  - EVA, MSA, EMA Solutions
- **SmartArray support identical to existing**
- **Direct-Attached SCSI support of Itanium® Infrastructure**

Backplane RAID Support (SCSI)
- **U160 (SmartArray) Q4 2002**
- **U320 (SmartArray) H2 2003**

Hardware Mirroring Support
- **EVA/DRM Support (H1 2003)**

Hardware Mirroring Support
- **EVA/DRM Enhanced Support (H1 2004)**
  - **Active/Active, Multi-Site**
  - **Viable Alternative to HBVS**

OpenVMS Enterprise Backup Solutions Roadmap



HP OpenView Data Protector
- Initial Release V5.1 (Q3 2003)
  - First version with OpenVMS support
  - Media Agent , Disk Agent, ODS5

HP OpenView Data Protector
- Enhancements – Oracle, Oracle Rdb

Legato NetWorker
- Initial Release (Q4 2002)
  - Client, Storage Node

Legato NetWorker
- Enhancements – Oracle, Oracle Rdb, ODS5 Support

Archive/Backup System V4.1:
- Support for new OS Versions
- More scheduling options
- GUI enhancements
- NSR support (M2402)
- Remote cataloging

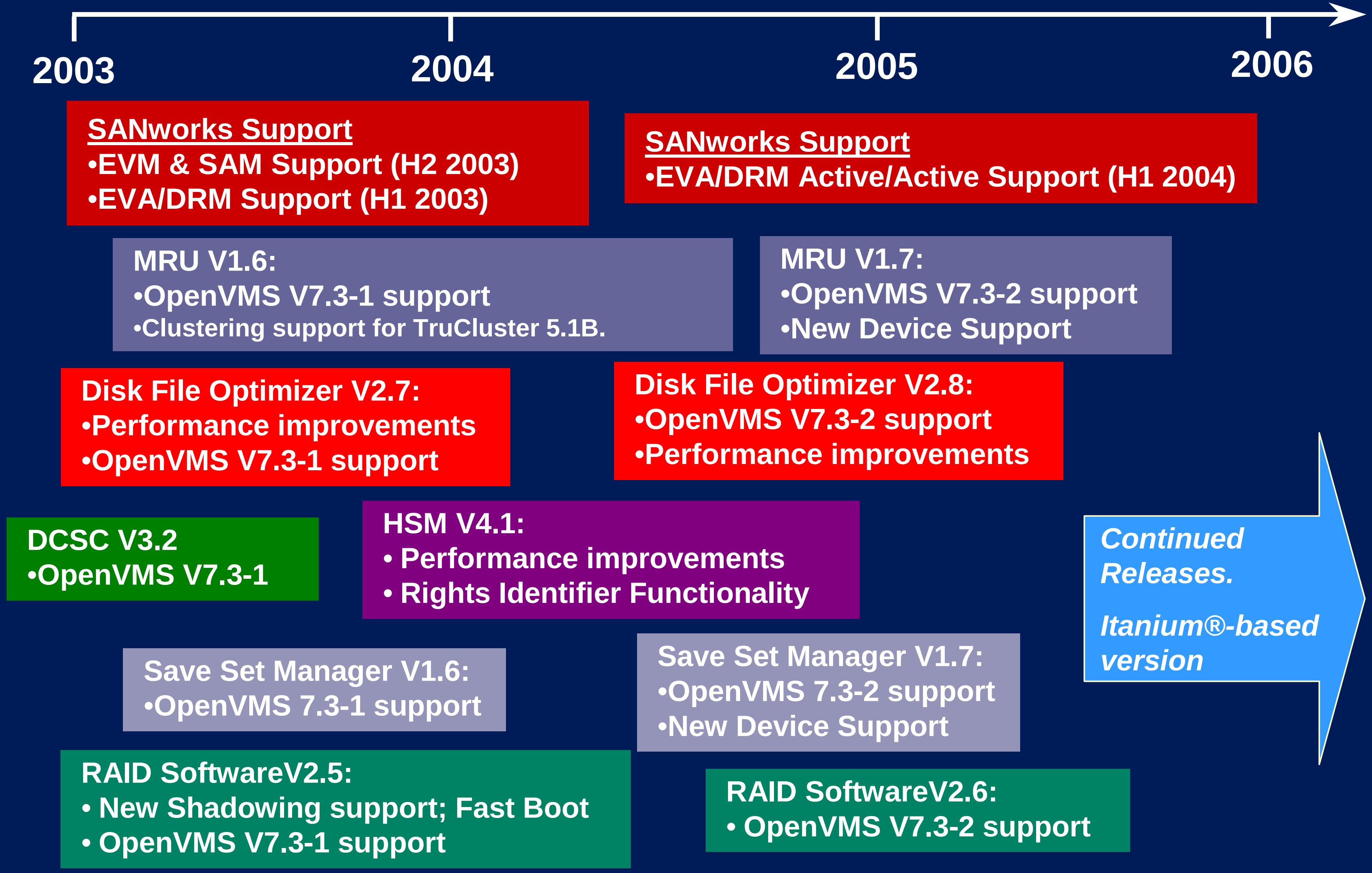
Archive/Backup System V4.2 & HSM V4.2
- Support for new OS versions
- New device support
- Bug fixes

Storage Library System V2.9H:
- New device support

Continued Releases.

Itanium®-based version

OpenVMS Storage SW Roadmap



SANworks Support
- •EVM & SAM Support (H2 2003)
- •EVA/DRM Support (H1 2003)

SANworks Support
- •EVA/DRM Active/Active Support (H1 2004)

MRU V1.6:
- •OpenVMS V7.3-1 support
- •Clustering support for TruCluster 5.1B.

MRU V1.7:
- •OpenVMS V7.3-2 support
- •New Device Support

Disk File Optimizer V2.7:
- •Performance improvements
- •OpenVMS V7.3-1 support

Disk File Optimizer V2.8:
- •OpenVMS V7.3-2 support
- •Performance improvements

DCSC V3.2
- •OpenVMS V7.3-1

HSM V4.1:
- Performance improvements
- Rights Identifier Functionality

Continued Releases.

Itanium®-based version

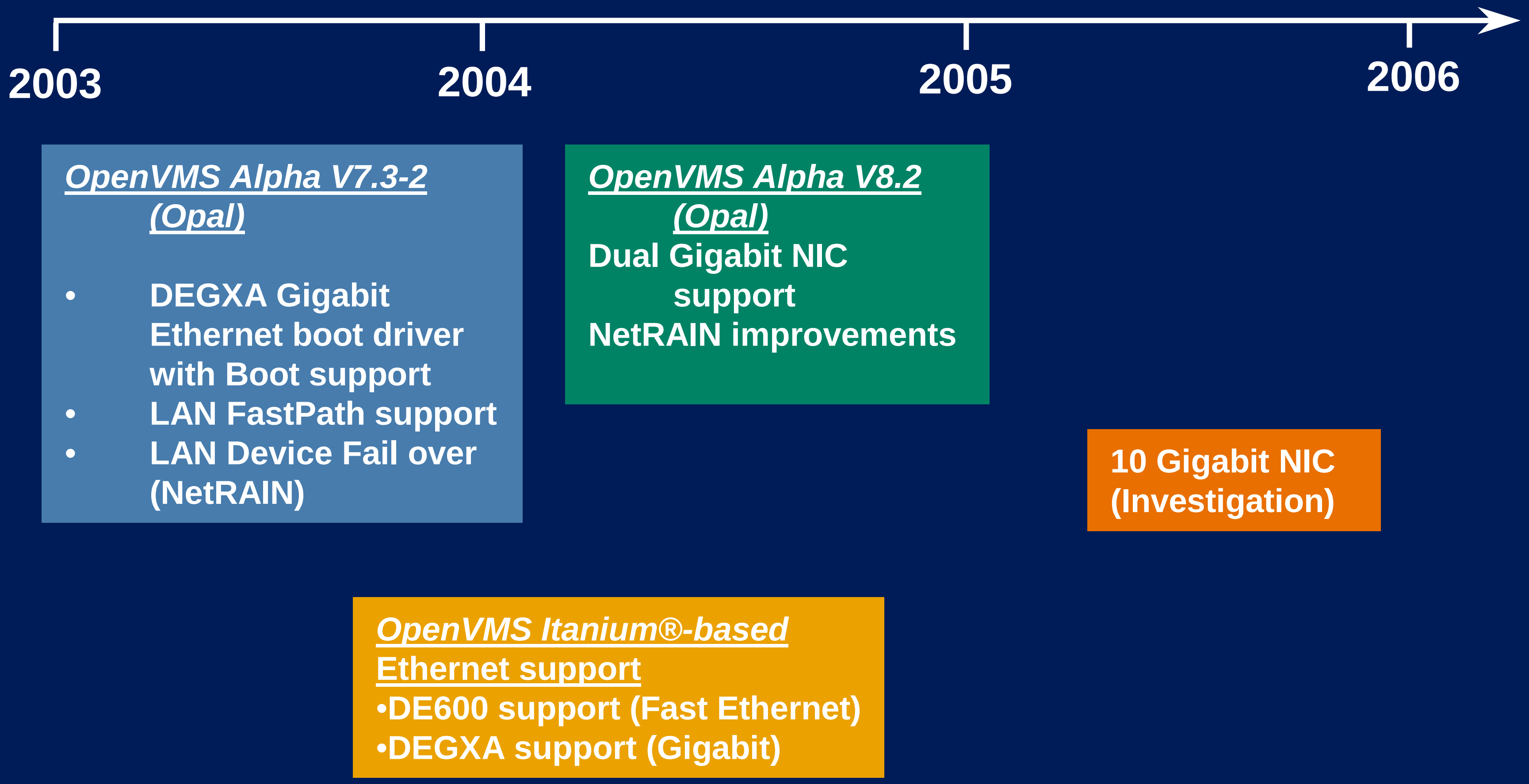
Save Set Manager V1.6:
- •OpenVMS 7.3-1 support

Save Set Manager V1.7:
- •OpenVMS 7.3-2 support
- •New Device Support

RAID SoftwareV2.5:
- New Shadowing support; Fast Boot
- OpenVMS V7.3-1 support

RAID SoftwareV2.6:
- OpenVMS V7.3-2 support

OpenVMS LAN HW Roadmap



OpenVMS Alpha V7.3-2 (Opal)

- **DEGXA Gigabit Ethernet boot driver with Boot support**
- **LAN FastPath support**
- **LAN Device Fail over (NetRAIN)**

OpenVMS Alpha V8.2 (Opal)

Dual Gigabit NIC support

NetRAIN improvements

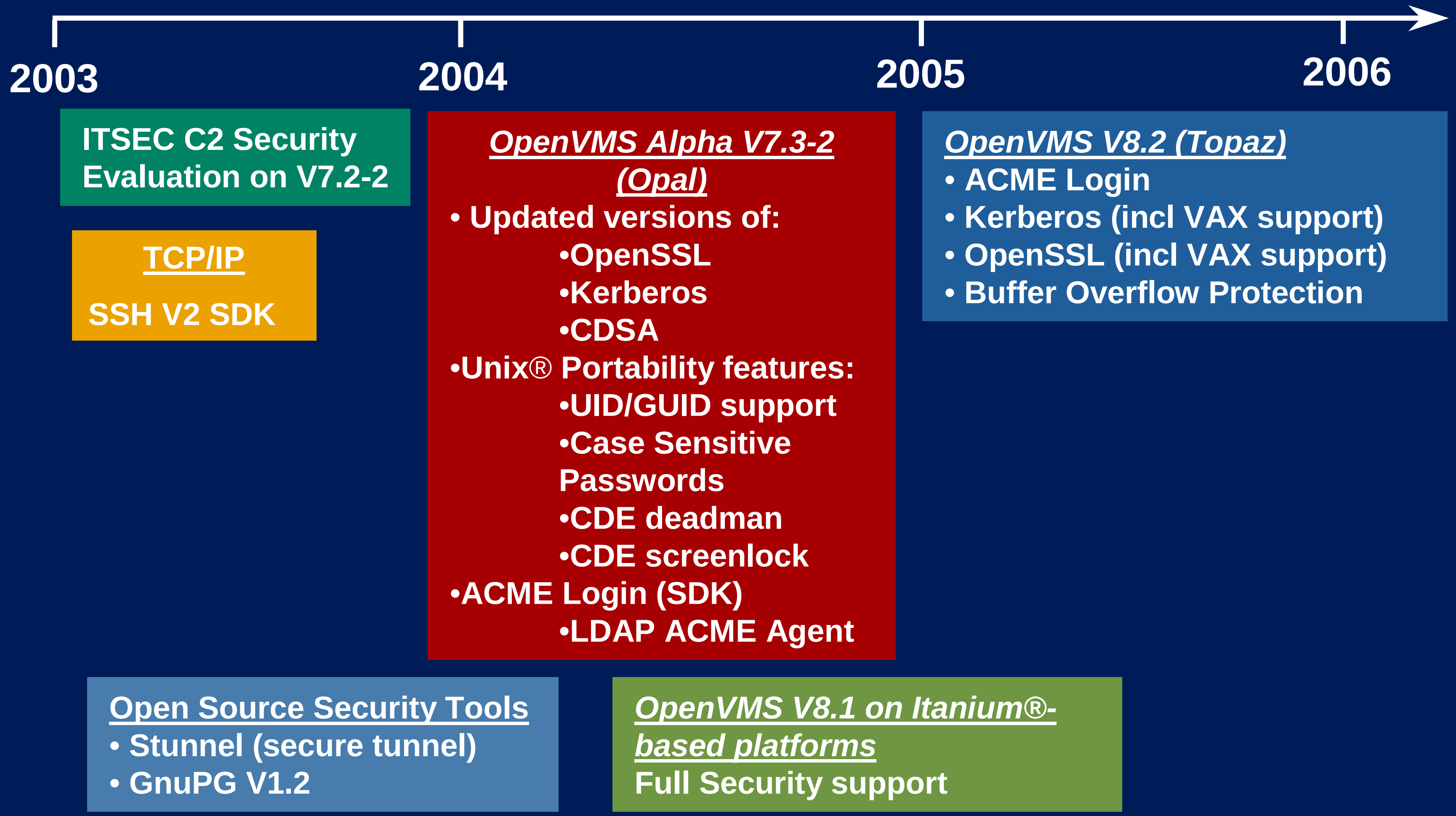
10 Gigabit NIC (Investigation)

OpenVMS Itanium®-based Ethernet support

•DE600 support (Fast Ethernet)

•DEGXA support (Gigabit)

OpenVMS Security Roadmap



ITSEC C2 Security Evaluation on V7.2-2

TCP/IP

SSH V2 SDK

OpenVMS Alpha V7.3-2 (Opal)

- Updated versions of:
  - OpenSSL
  - Kerberos
  - CDSA
- Unix® Portability features:
  - UID/GUID support
  - Case Sensitive Passwords
  - CDE deadman
  - CDE screenlock
- ACME Login (SDK)
  - LDAP ACME Agent

OpenVMS V8.2 (Topaz)

- ACME Login
- Kerberos (incl VAX support)
- OpenSSL (incl VAX support)
- Buffer Overflow Protection

Open Source Security Tools

- Stunnel (secure tunnel)
- GnuPG V1.2

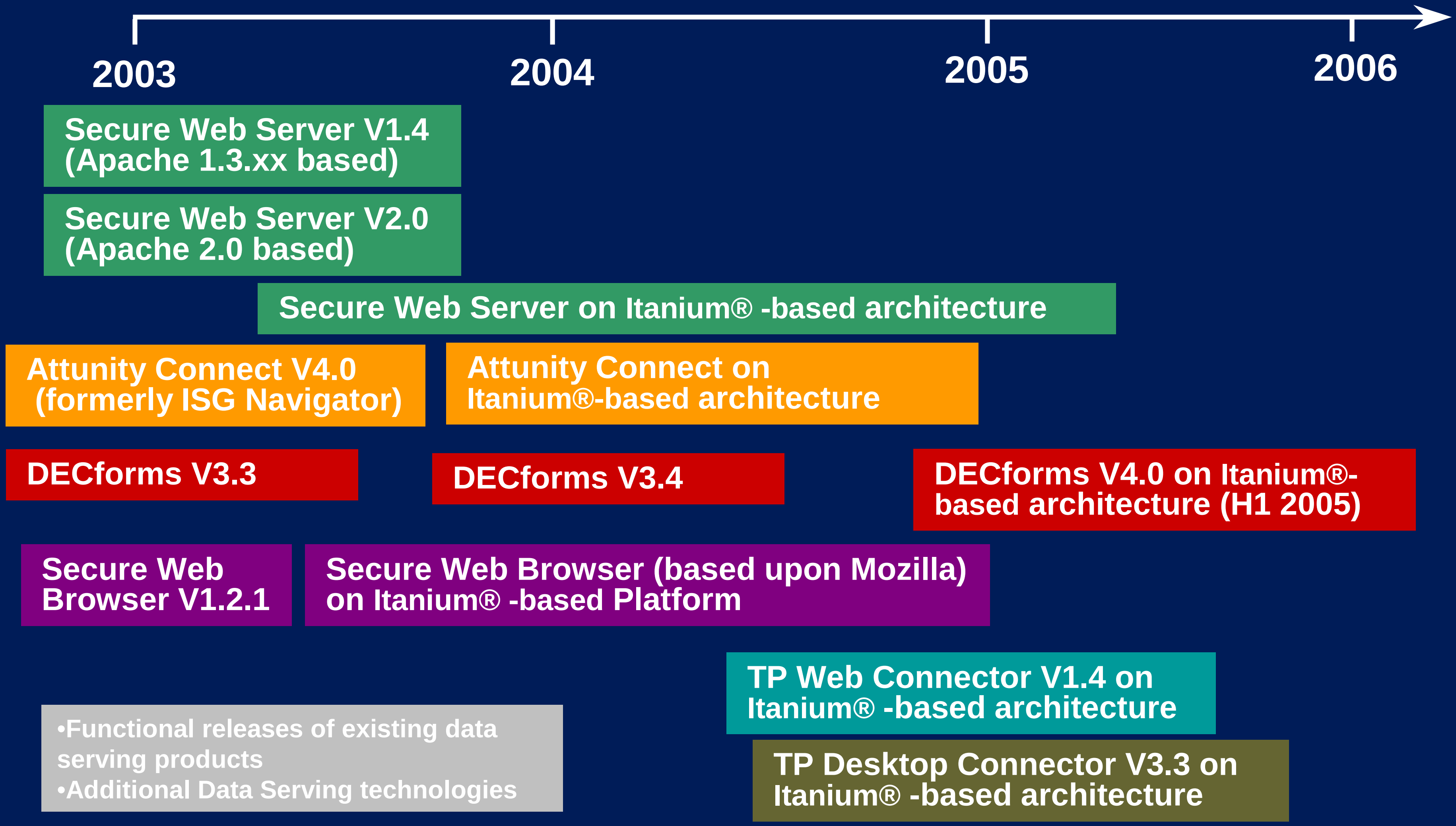
OpenVMS V8.1 on Itanium®-based platforms

Full Security support

OpenVMS eBusiness Integration Technologies

- Data Serving
- Integration
- Collaborative Computing

OpenVMS *e*Business Integration Technologies



2003

2004

2005

2006

Secure Web Server V1.4 (Apache 1.3.xx based)

Secure Web Server V2.0 (Apache 2.0 based)

Secure Web Server on Itanium® -based architecture

Attunity Connect V4.0 (formerly ISG Navigator)

Attunity Connect on Itanium®-based architecture

DECforms V3.3

DECforms V3.4

DECforms V4.0 on Itanium®-based architecture (H1 2005)

Secure Web Browser V1.2.1

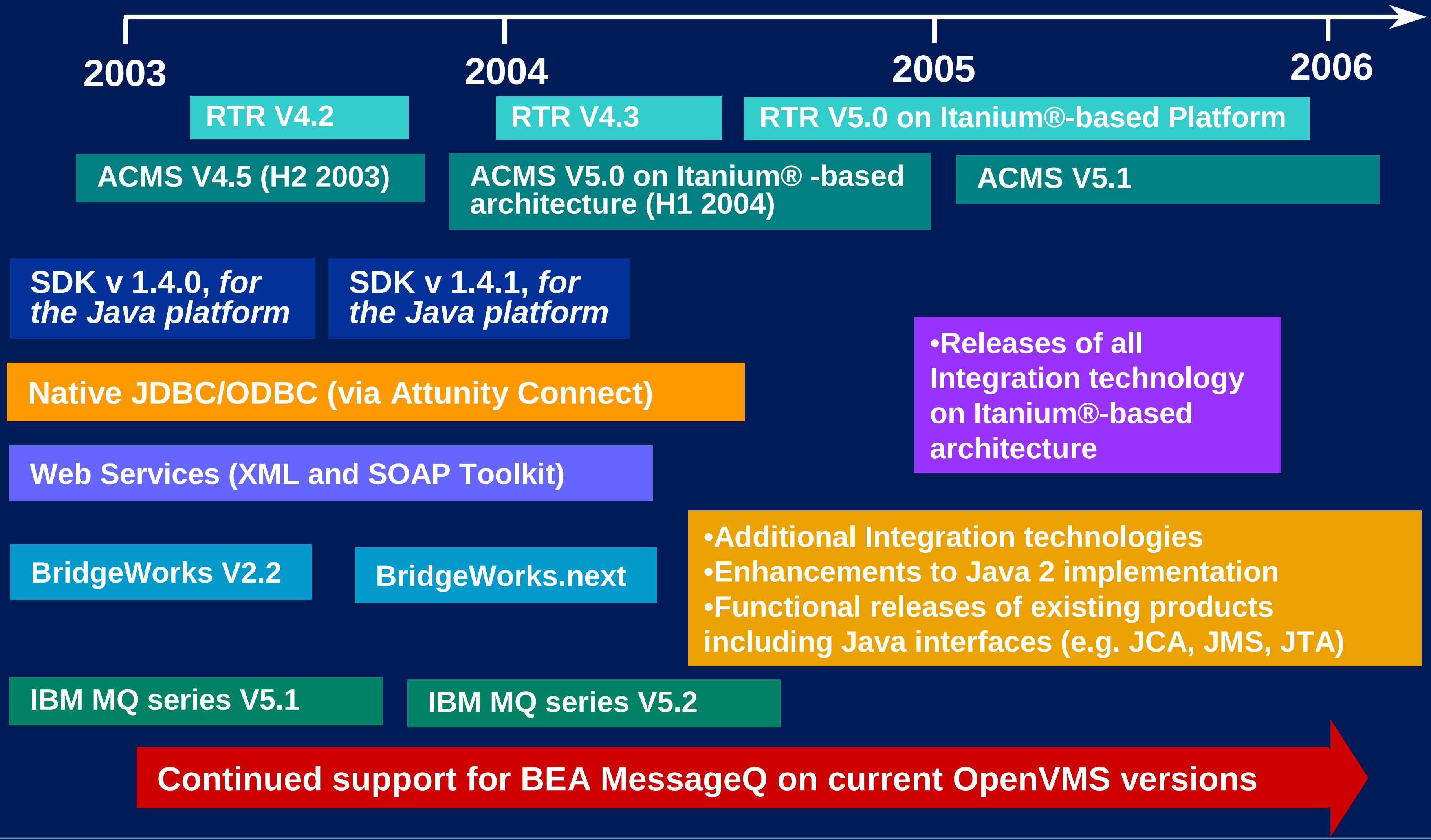
Secure Web Browser (based upon Mozilla) on Itanium® -based Platform

TP Web Connector V1.4 on Itanium® -based architecture

TP Desktop Connector V3.3 on Itanium® -based architecture

- Functional releases of existing data serving products
- Additional Data Serving technologies

OpenVMS *e*Business Integration Technologies



2003

2004

2005

2006

RTR V4.2

RTR V4.3

RTR V5.0 on Itanium®-based Platform

ACMS V4.5 (H2 2003)

ACMS V5.0 on Itanium® -based architecture (H1 2004)

ACMS V5.1

SDK v 1.4.0, *for the Java platform*

SDK v 1.4.1, *for the Java platform*

- Releases of all Integration technology on Itanium®-based architecture

Native JDBC/ODBC (via Attunity Connect)

Web Services (XML and SOAP Toolkit)

BridgeWorks V2.2

BridgeWorks.next

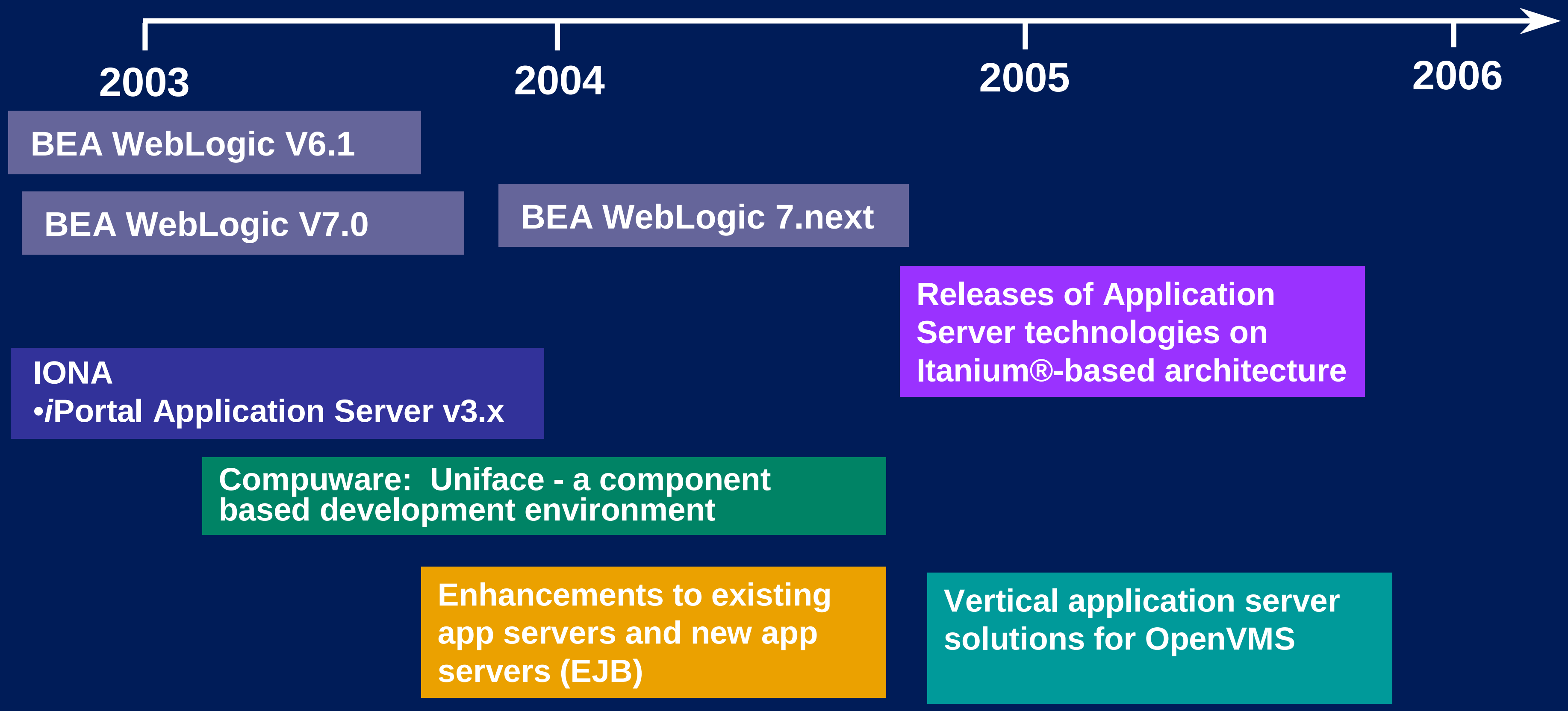
- Additional Integration technologies
- Enhancements to Java 2 implementation
- Functional releases of existing products including Java interfaces (e.g. JCA, JMS, JTA)

IBM MQ series V5.1

IBM MQ series V5.2

Continued support for BEA MessageQ on current OpenVMS versions

OpenVMS *e*Business Integration Technologies



2003

2004

2005

2006

BEA WebLogic V6.1

BEA WebLogic V7.0

BEA WebLogic 7.next

Releases of Application Server technologies on Itanium®-based architecture

IONA
•*i*Portal Application Server v3.x

Compuware: Uniface - a component based development environment

Enhancements to existing app servers and new app servers (EJB)

Vertical application server solutions for OpenVMS

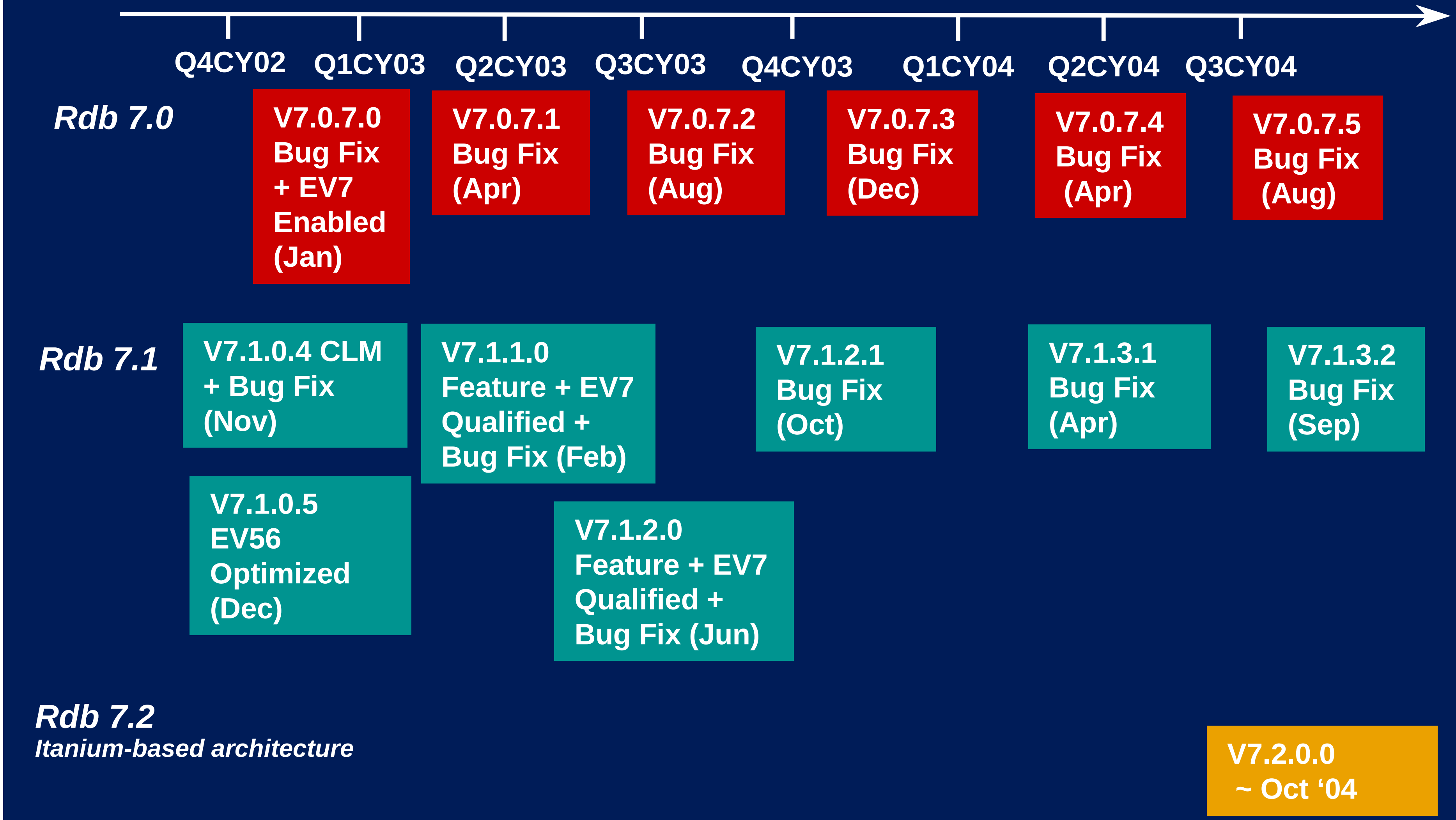
Database Solutions

Oracle® 8i/9i OpenVMS Roadmap

	Currently Supported	Q1CY03	Q3CY03	Q4CY03
Oracle Server	•Oracle 8iR3 (8.1.7) •Oracle 9iR1 (9.0.1) •Oracle 9iR2 (9.2) – 20% perf boost		•Oracle 9iR2	•Oracle 10iR1
Patchsets	•8.1.7.4 •9.0.1.3	•9.0.1.4		•9.2.0.4
Oracle Apps. & Tools	•11.0.3 w/8173(SP) •11.5.7 w/8173 (11i) •10.7 w/8173	•11.5.8 w/8173, 9.0.1(SP)		
OS Cert	•7.2-2, 7.3, 7.3-1 w/8iR3 •7.2-2, 7.3, 7.3-1 w/9iR1 •7.3, 7.3-1 w/9iR2 •Marvel w/8iR3,9iR1,9iR2		•7.3-2 w/8iR3, 9iR1, 9iR2	

Release dates are shown as planned;
not guaranteed and subject to change

Oracle® Rdb Roadmap



Q4CY02 Q1CY03 Q2CY03 Q3CY03 Q4CY03 Q1CY04 Q2CY04 Q3CY04

Rdb 7.0

V7.0.7.0 Bug Fix + EV7 Enabled (Jan)

V7.0.7.1 Bug Fix (Apr)

V7.0.7.2 Bug Fix (Aug)

V7.0.7.3 Bug Fix (Dec)

V7.0.7.4 Bug Fix (Apr)

V7.0.7.5 Bug Fix (Aug)

Rdb 7.1

V7.1.0.4 CLM + Bug Fix (Nov)

V7.1.0.5 EV56 Optimized (Dec)

V7.1.1.0 Feature + EV7 Qualified + Bug Fix (Feb)

V7.1.2.0 Feature + EV7 Qualified + Bug Fix (Jun)

V7.1.2.1 Bug Fix (Oct)

V7.1.3.1 Bug Fix (Apr)

V7.1.3.2 Bug Fix (Sep)

Rdb 7.2

Itanium-based architecture

V7.2.0.0 ~ Oct ‘04

System Management

- hp OpenView Integration Planning
- Partner OpenVMS Solutions
- hp Web Management Agents
- hp OpenVMS Solutions

hp OpenView Integration Planning

Available Today

Network Node Manager:

- OpenVMS systems run the Insight Management Agents

OpenView Operations:

- Manage OpenVMS systems from HP OpenView Operations
- Available from AppMind

Coming Soon

OpenView Storage Data Protector (OmniBack):

- Disk Manager & Media Manager for OpenVMS available Q2CY2003

Future Planning

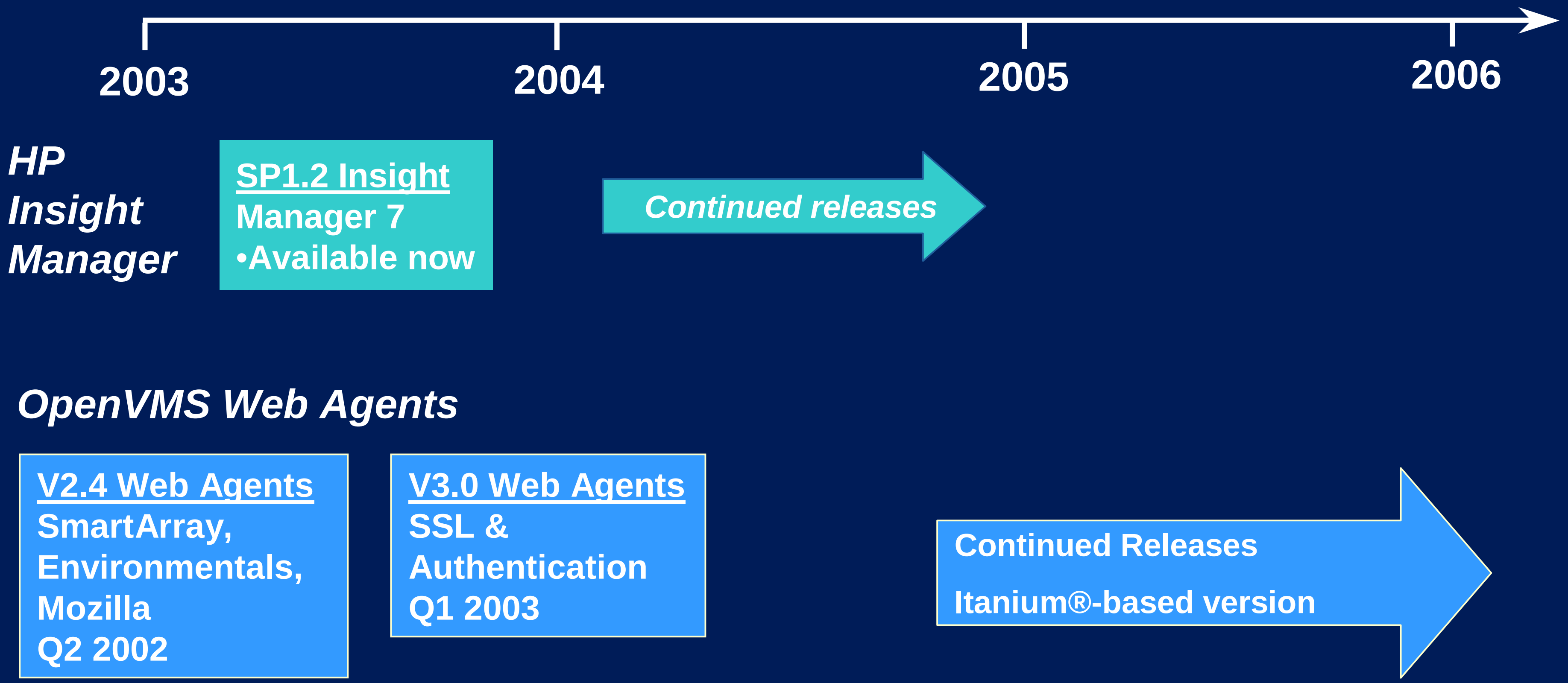
Storage Area Management Client:

- Storage device management, performance analysis for storage systems, and storage resource management capabilities

OpenView Operations:

- Native HP agent investigation

System Management Roadmap
Web Management Agents



2003

2004

2005

2006

HP Insight Manager

SP1.2 Insight Manager 7
•Available now

Continued releases

OpenVMS Web Agents

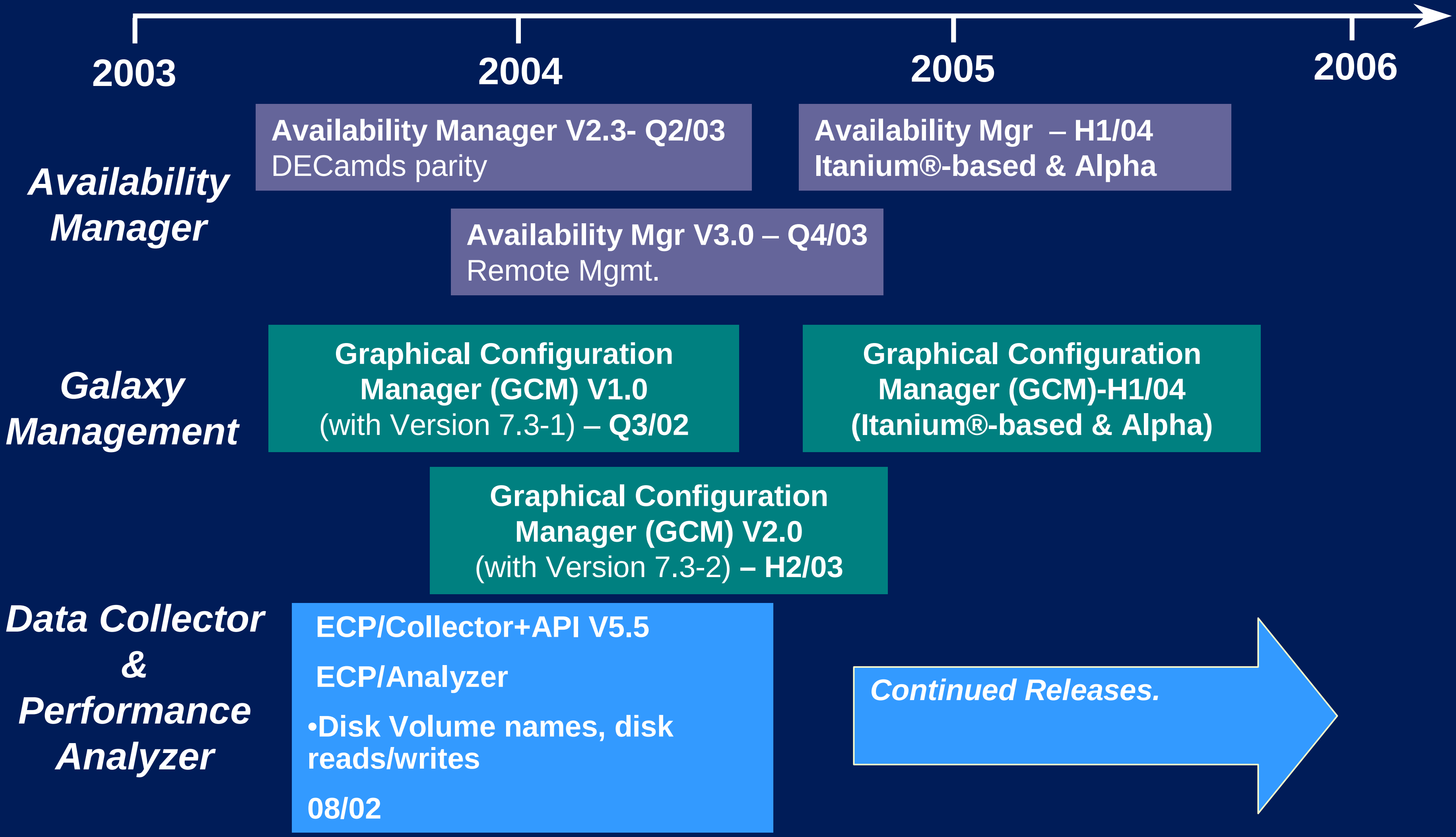
V2.4 Web Agents
SmartArray, Environmentals, Mozilla
Q2 2002

V3.0 Web Agents
SSL & Authentication
Q1 2003

Continued Releases

Itanium®-based version

System Management Roadmap
Integrated O/S Solutions



Availability Manager

Availability Manager V2.3- Q2/03
DECamds parity

Availability Mgr – H1/04
Itanium®-based & Alpha

Availability Mgr V3.0 – Q4/03
Remote Mgmt.

Galaxy Management

Graphical Configuration Manager (GCM) V1.0
(with Version 7.3-1) – **Q3/02**

Graphical Configuration Manager (GCM)-H1/04
(Itanium®-based & Alpha)

Graphical Configuration Manager (GCM) V2.0
(with Version 7.3-2) **– H2/03**

Data Collector & Performance Analyzer

ECP/Collector+API V5.5

ECP/Analyzer

•Disk Volume names, disk reads/writes

08/02

Continued Releases.

Networking Products

- TCP/IP Services
- DECnet and WAN
- File & Print

TCP/IP Services for OpenVMS

2003 2004 2005 2006

TCP/IP V5.4 (Oct 2003)
Featuring IP security and performance enhancements

- SSHv2 client functionality
- FailSAFE IP (IP fail over)
- Scaleable kernel
- TCP/IP kernel updated
- Perf enhancements to Telnet server locking
- NFS Server Performance enhancement
- 10k+ BG device support
- Bind 9.2.1 upgrade
- SSL POP Security
- INETDRIVER perf update
- TCPDUMP Support

TCP/IP V5.5 on Itanium® (H1 2004)

- Support for OVMS V8.2

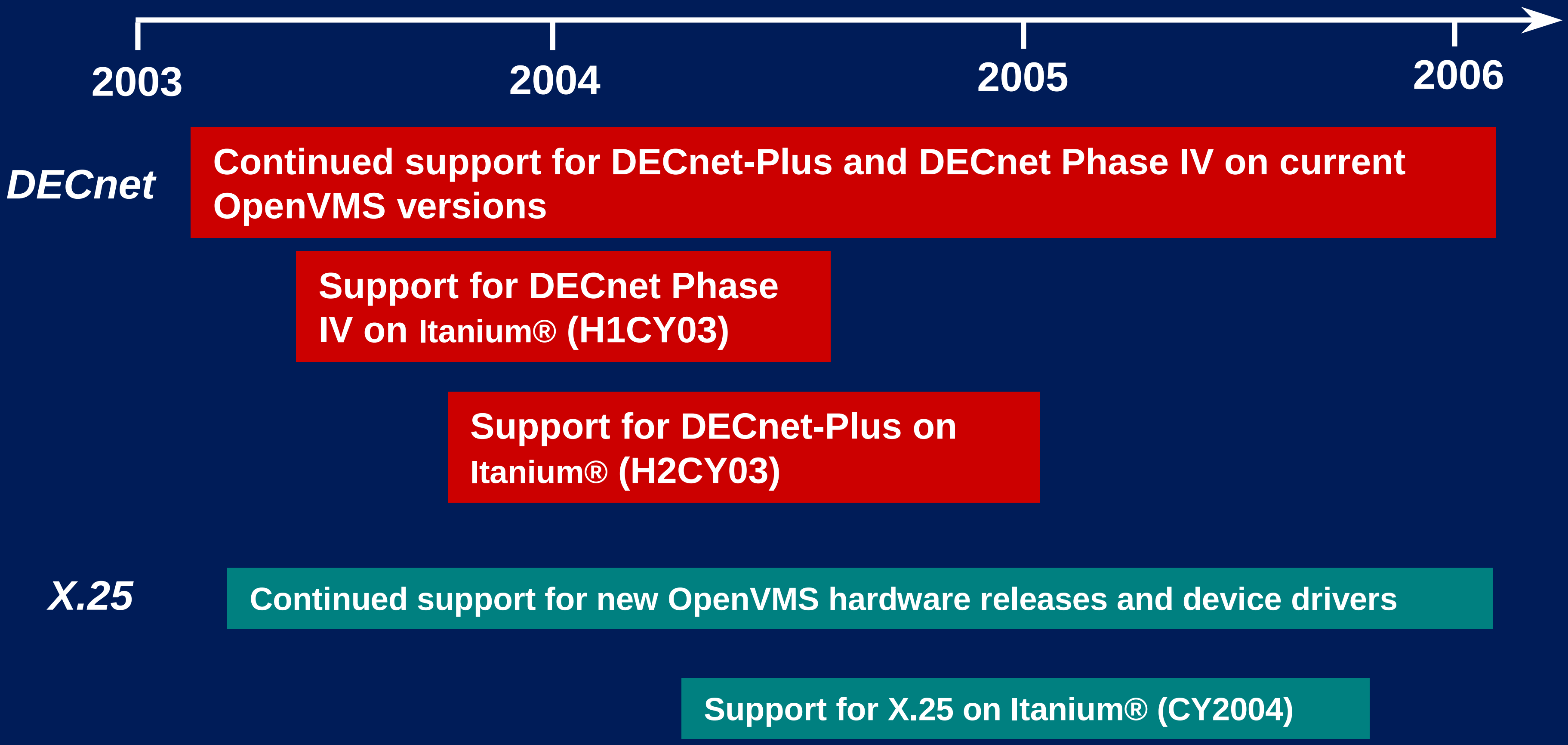
TCP/IP (H2 2005)
Continued focus on performance & security

- BIND V9 Resolver
- DHCPv6
- IPv6 Routing
- Standards
- Improved cluster support
- Multi media support
- SCTP Support

FailSAFE IP PCSI EAK (Feb 2003)

SSHv2 PCSI EAK (Feb 2003)

DECnet & X.25 Product Roadmap



2003 2004 2005 2006

DECnet

Continued support for DECnet-Plus and DECnet Phase IV on current OpenVMS versions

Support for DECnet Phase IV on Itanium® (H1CY03)

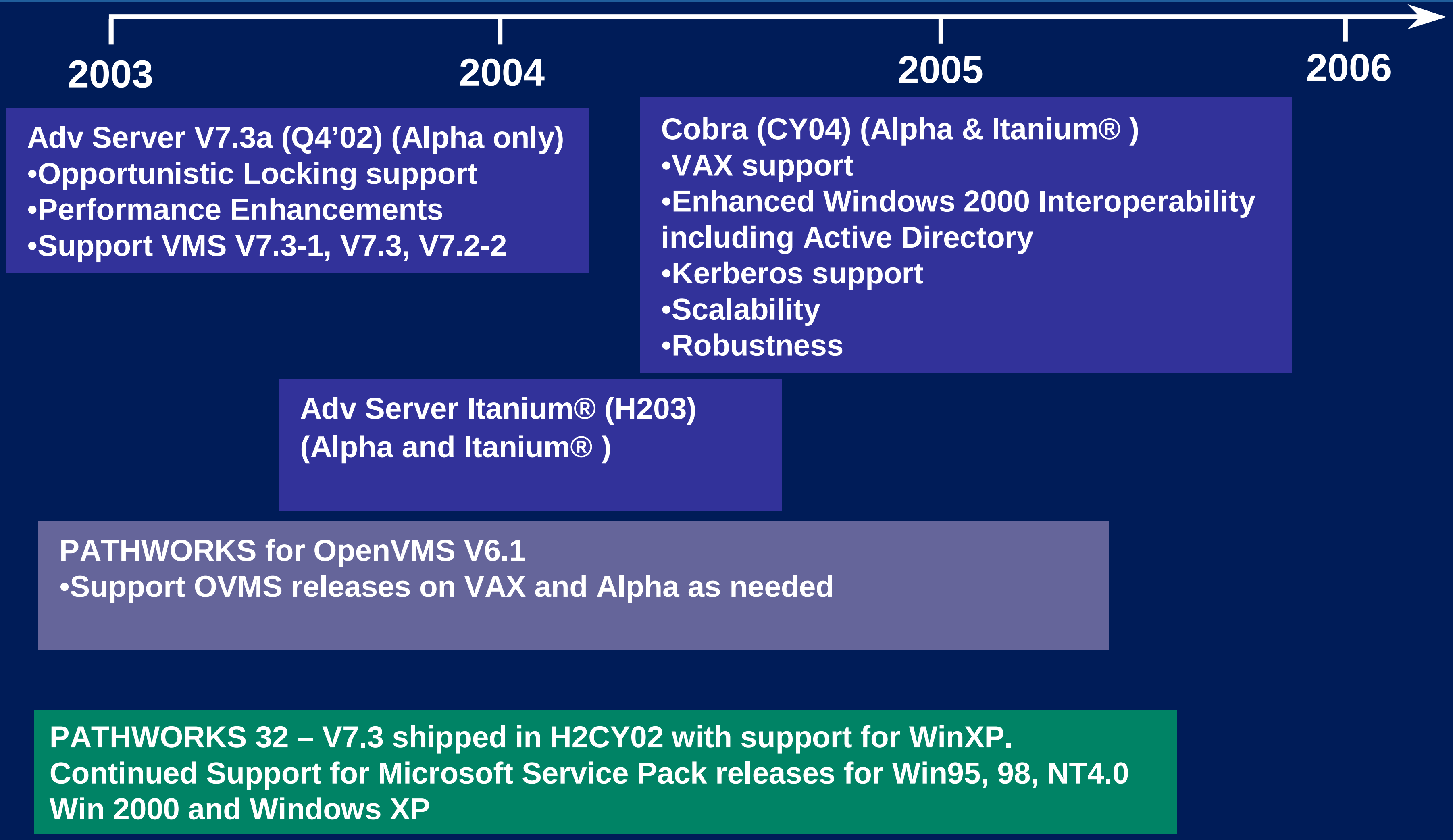
Support for DECnet-Plus on Itanium® (H2CY03)

X.25

Continued support for new OpenVMS hardware releases and device drivers

Support for X.25 on Itanium® (CY2004)

Enterprise File and Print



Adv Server V7.3a (Q4'02) (Alpha only)
- Opportunistic Locking support
- Performance Enhancements
- Support VMS V7.3-1, V7.3, V7.2-2

Cobra (CY04) (Alpha & Itanium®)
- VAX support
- Enhanced Windows 2000 Interoperability including Active Directory
- Kerberos support
- Scalability
- Robustness

Adv Server Itanium® (H203) (Alpha and Itanium®)

PATHWORKS for OpenVMS V6.1
- Support OVMS releases on VAX and Alpha as needed

PATHWORKS 32 – V7.3 shipped in H2CY02 with support for WinXP. Continued Support for Microsoft Service Pack releases for Win95, 98, NT4.0 Win 2000 and Windows XP

DECprint Supervisor (DCPS) Roadmap

2003 2004 2005 2006

DCPS V2.1: (Q3CY02)

- New printers supported: HP LaserJet 2200, 4100, & 9000, Genicom, Xerox, Lexmark
- IBM InfoPrint support for Bell Helicopter
- OpenVMS V7.3-1 support

DCPS V2.2: (Q1CY03)

- HP LaserJet 2300, 4100 mfp, 4200, 4300, 5100 and 9000 mfp support
- HP Color LaserJet 2500, 5500 and 9500 support
- Autostart support
- Bug fixes
- Support for New EV7 Update Release

DCPS V2.1 added feature:

- HP Color LaserJet 4600 support

DCPS V2.3: (Q3 CY03)

- IPV6 protocol support

DCPS Future Functionality:

- Uni-directional Printer support
  - Multi-functional printer support
- Port to Itanium
- PPD: PostScript Printer Description

Transaction Processing and Middleware Software

Reliable Transaction Router (RTR)

2003

2004

2005

2006

RTR V4.2

- Quality enhancement release
- Java RTR Toolkit
- Platform support:
  - OpenVMS Alpha
  - OpenVMS VAX
  - Tru64 UNIX
  - Sun Solaris
  - Windows®

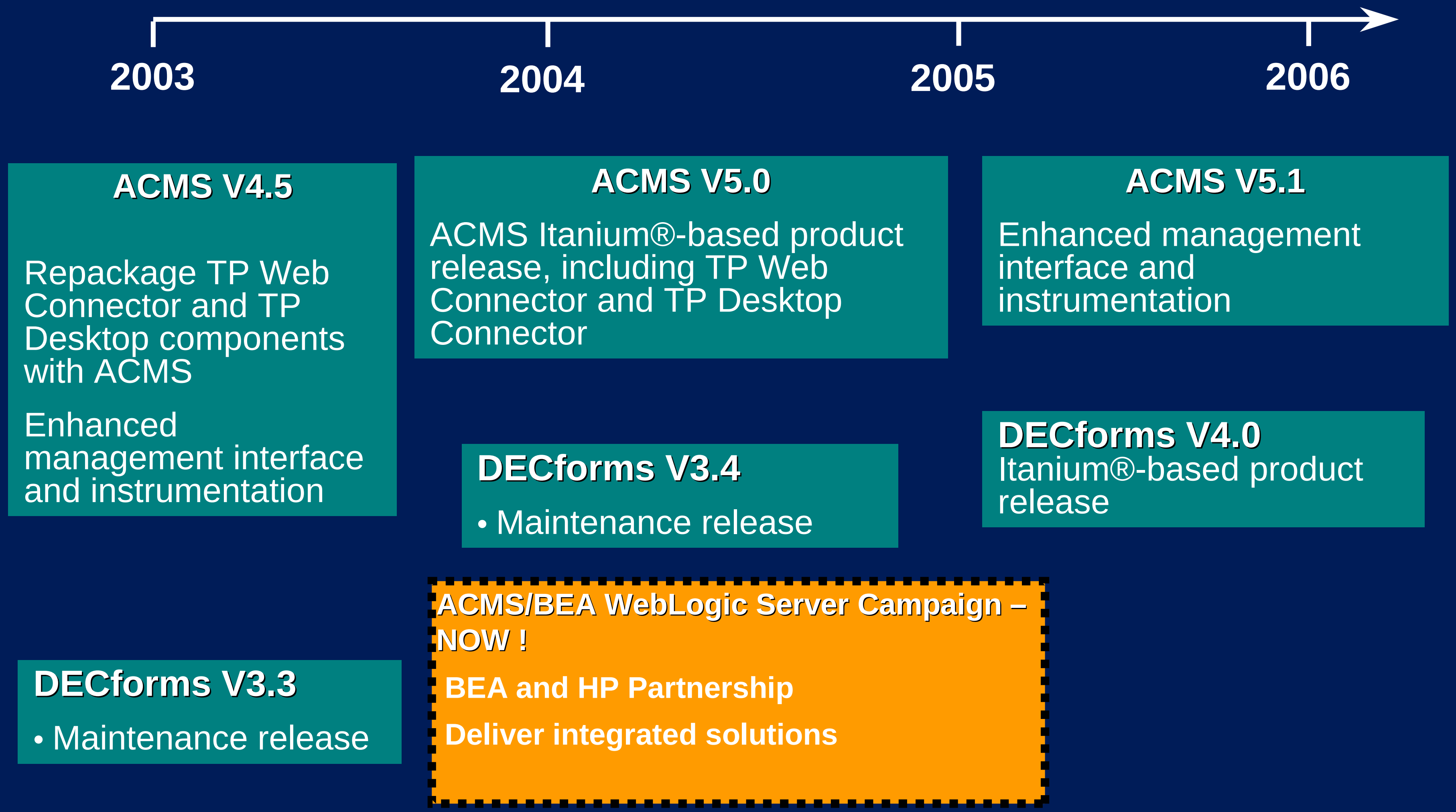
RTR V4.3

- Quality enhancement release
- RTR configuration fault detection web browser interface.
- Platform support:
  - OpenVMS Alpha
  - OpenVMS Itanium®-based
  - Tru64 UNIX
  - Sun Solaris
  - Windows®

RTR V5.0 features being considered include:

- TCP/IP V6 support
- Specific customer requests
- Integrate RTR J2EE toolkit
- Platform support:
  - OpenVMS Alpha
  - OpenVMS Itanium®-based
  - Tru64 UNIX
  - Sun Solaris
  - Windows®

ACMS and DECforms Roadmaps



2003 2004 2005 2006

ACMS V4.5

Repackage TP Web Connector and TP Desktop components with ACMS

Enhanced management interface and instrumentation

ACMS V5.0

ACMS Itanium®-based product release, including TP Web Connector and TP Desktop Connector

ACMS V5.1

Enhanced management interface and instrumentation

DECforms V3.4

- Maintenance release

DECforms V4.0
Itanium®-based product release

DECforms V3.3

- Maintenance release

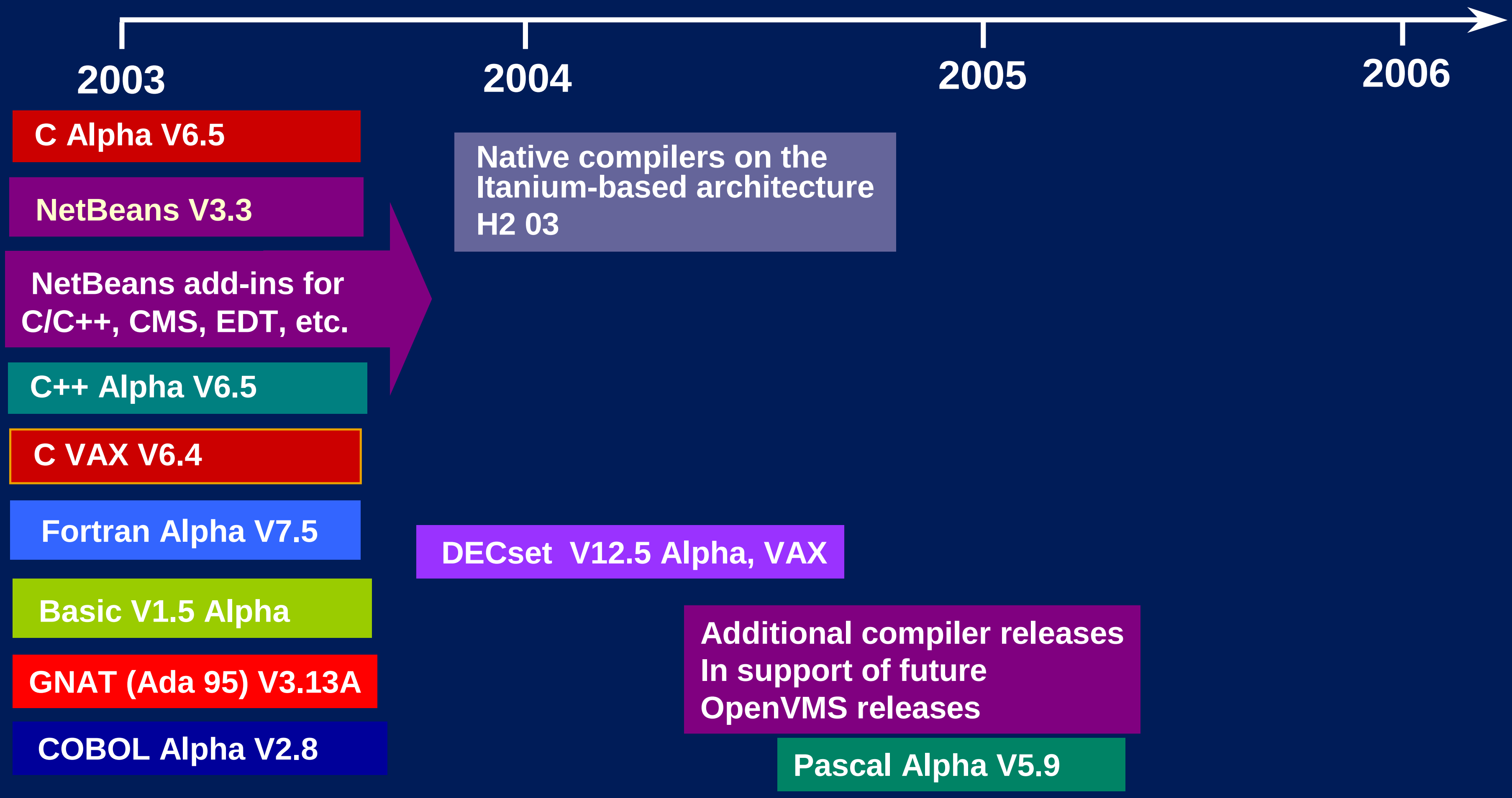
ACMS/BEA WebLogic Server Campaign – NOW !

BEA and HP Partnership

Deliver integrated solutions

Application Development Into The Future

Application Development and Deployment on OpenVMS



2003

2004

2005

2006

C Alpha V6.5

NetBeans V3.3

NetBeans add-ins for C/C++, CMS, EDT, etc.

C++ Alpha V6.5

C VAX V6.4

Fortran Alpha V7.5

Basic V1.5 Alpha

GNAT (Ada 95) V3.13A

COBOL Alpha V2.8

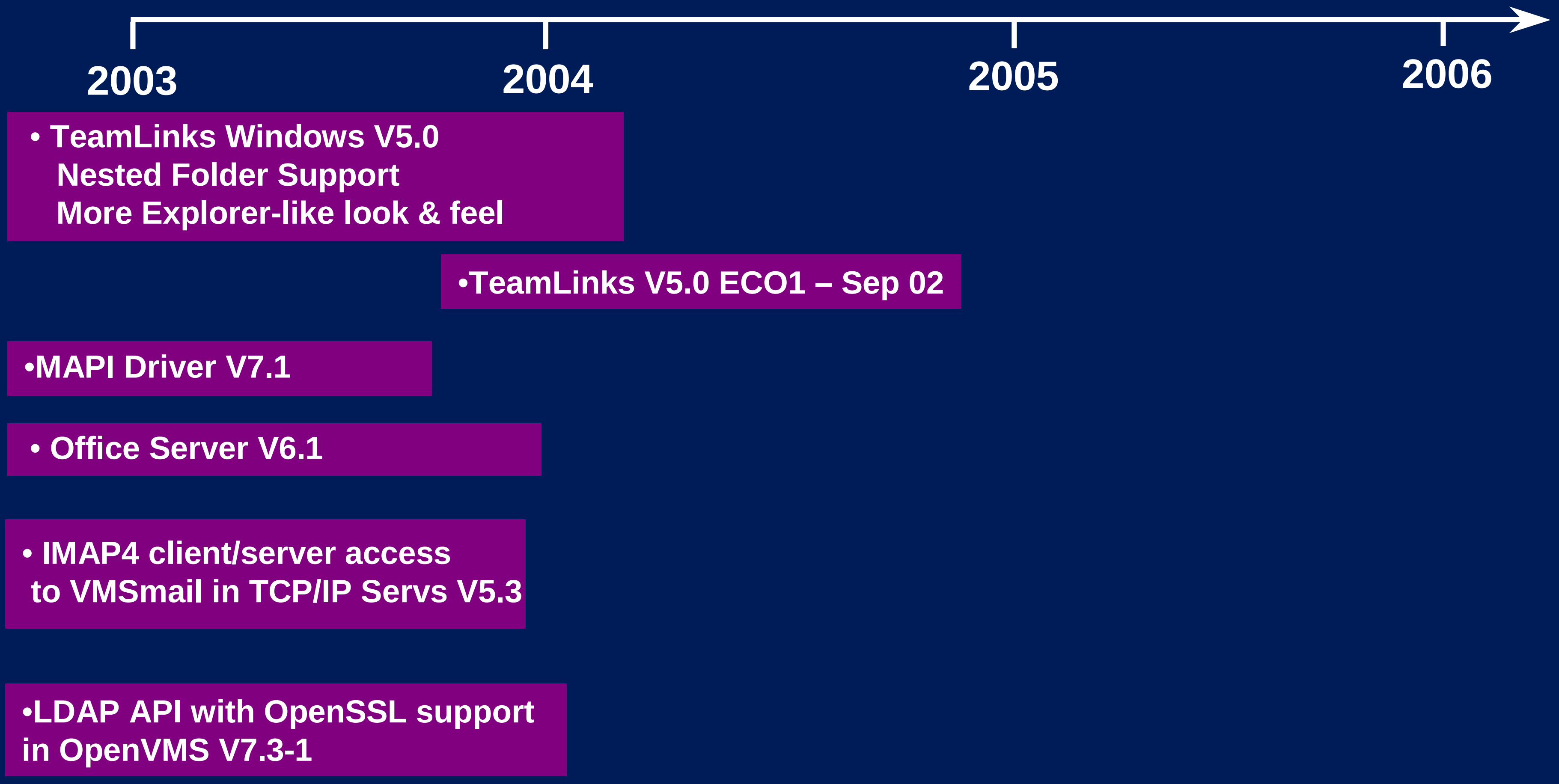
Native compilers on the Itanium-based architecture
H2 03

DECset V12.5 Alpha, VAX

Additional compiler releases
In support of future
OpenVMS releases

Pascal Alpha V5.9

Mail and Messaging Roadmap



- TeamLinks Windows V5.0
  Nested Folder Support
  More Explorer-like look & feel

•TeamLinks V5.0 ECO1 – Sep 02

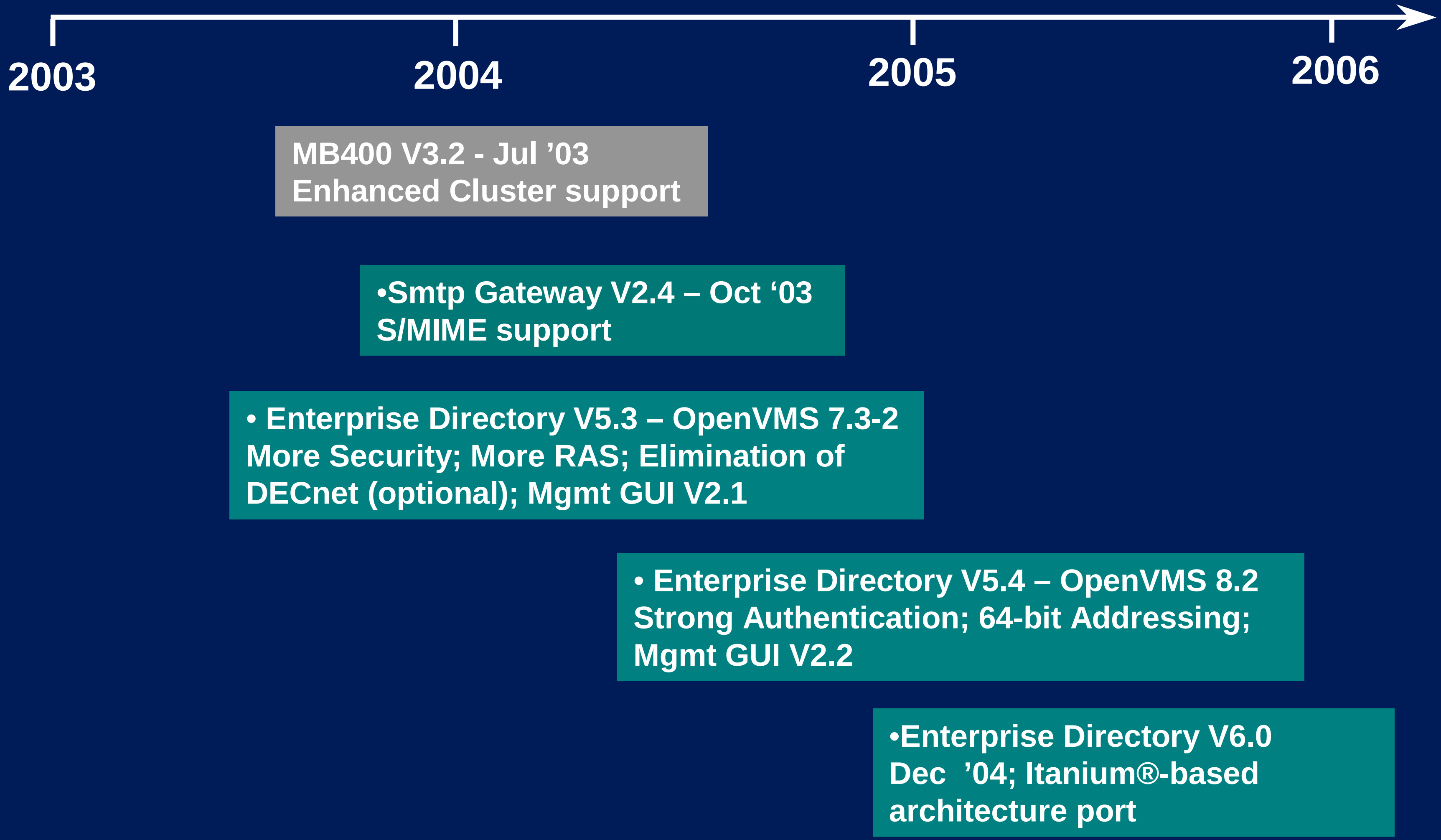
•MAPI Driver V7.1

- Office Server V6.1

- IMAP4 client/server access
  to VMSmail in TCP/IP Servs V5.3

•LDAP API with OpenSSL support
in OpenVMS V7.3-1

Directory and Mail Backbone Roadmap



MB400 V3.2 - Jul ’03
Enhanced Cluster support

•Smtp Gateway V2.4 – Oct ‘03
S/MIME support

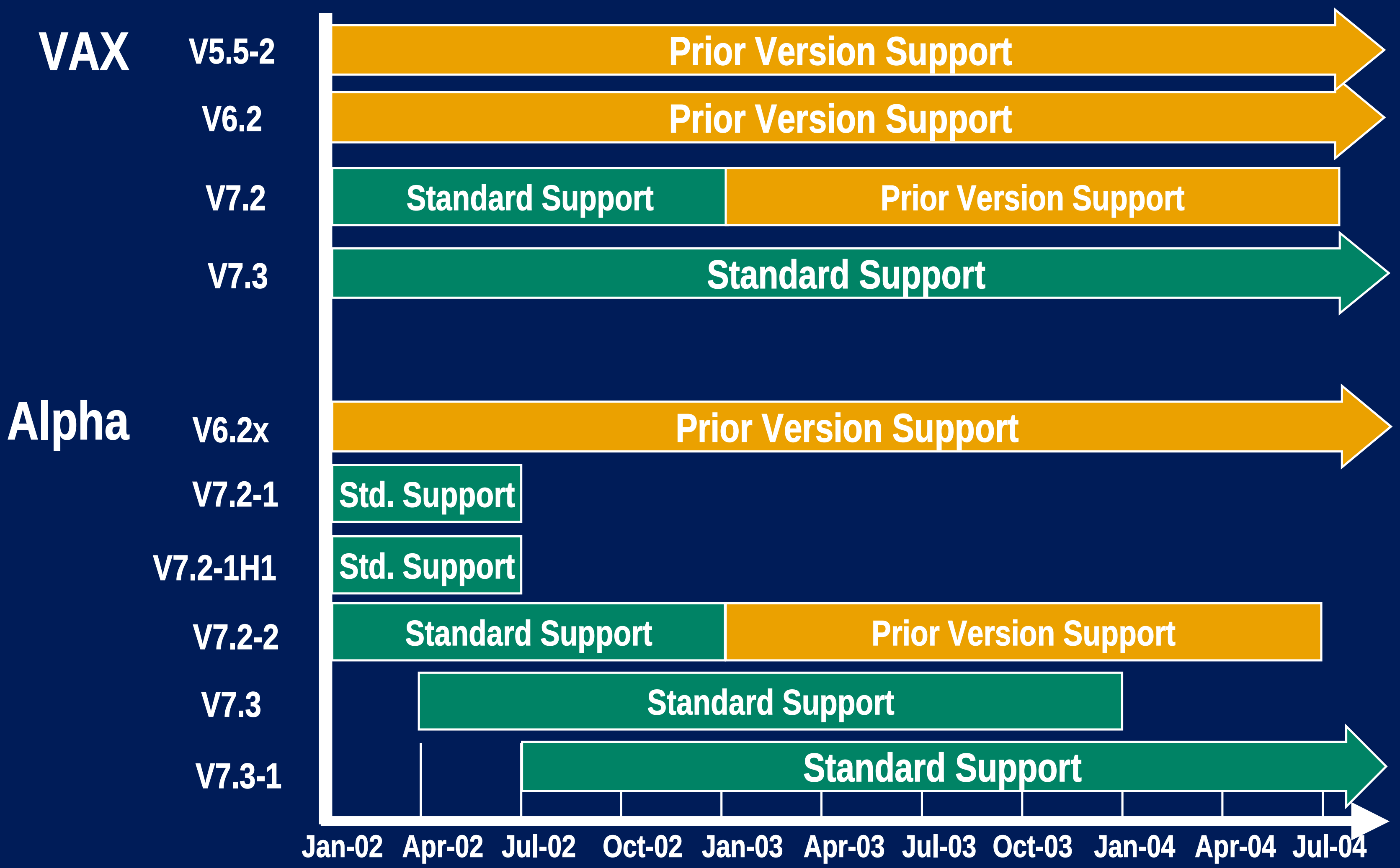
• Enterprise Directory V5.3 – OpenVMS 7.3-2
More Security; More RAS; Elimination of DECnet (optional); Mgmt GUI V2.1

• Enterprise Directory V5.4 – OpenVMS 8.2
Strong Authentication; 64-bit Addressing; Mgmt GUI V2.2

•Enterprise Directory V6.0
Dec ’04; Itanium®-based architecture port

OpenVMS Service Support

OpenVMS Service Support Roadmap



VAX

V5.5-2 Prior Version Support

V6.2 Prior Version Support

V7.2 Standard Support Prior Version Support

V7.3 Standard Support

Alpha

V6.2x Prior Version Support

V7.2-1 Std. Support

V7.2-1H1 Std. Support

V7.2-2 Standard Support Prior Version Support

V7.3 Standard Support

V7.3-1 Standard Support

Notice

Appendix J – HP OpenVMS Commitment Letter External

Hewlett-Packard Company

May 14, 2003

Mr. Bob Blackmore
Mr. Dale Batston
Mr. Ed Okeefe

Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's NL
Canada, A1B 3P6

Dear Mr. Blackmore,

With the merger of Compaq Computer Corporation and Hewlett-Packard Company behind us, I would like to summarize the positive outcome of the merger for OpenVMS. I am pleased to inform you that HP will continue with the previously committed AlphaServer and OpenVMS roadmaps. We delivered HP OpenVMS V7.3-1 in August 2002, delivered the Alpha EV7 technology in January 2003 and performed the first boot of OpenVMS on an Itanium®-based system January 31, 2003. Clearly, OpenVMS continues to withstand the test of time as we celebrate its 25th anniversary.

HP will deliver the AlphaServer roadmap announced in June 2001 along with the associated feature enhancements of OpenVMS on AlphaServer systems. This includes the EV79 version of the Alpha processor, which will be the follow-on to the newest generation, EV7-based HP AlphaServer systems supporting OpenVMS, Tru64 UNIX®, and Linux. HP will sell AlphaServer systems at least until 2006, with support through at least 2011.

OpenVMS remains a strategic product. We are committed to continuing the port of OpenVMS to Itanium architecture-based HP servers, and transitioning our HP OpenVMS application portfolio to the Itanium architecture as previously committed. We expect initial availability of OpenVMS on Itanium architecture-based HP servers in the first half of 2003 with an evaluation release for ISVs and early adopter customers, and a full production release in the second half of 2004.

ISVs have been a very strategic part of our success with OpenVMS in target markets such as Healthcare, Public Sector, and Finance. These ISVs are very excited about the opportunity that the Itanium architecture-based HP servers will provide to the long-term success of OpenVMS.

We are committed to enabling our customers to deploy Itanium-based HP systems on their own schedules and to making the transition to the Itanium architecture-based HP servers as smooth as possible. Existing OpenVMS applications will run on the new servers with little or no modification. To help facilitate this, we will provide source compatibility for OpenVMS applications, and where sources are not available, binary compatibility as well.

I want to personally assure you that the capabilities for which you have come to depend upon in OpenVMS – leadership clustering, high availability and “bullet-proof” operations – will continue to be delivered by HP. There is no more important asset to HP than you, our users.

In closing, be assured HP is committed to the published roadmaps for the OpenVMS operating system and the AlphaServer system family, ensuring product leadership now and in the future.

Should you have any questions or issues, please do not hesitate to contact me.

Mark Gorham
Vice President
OpenVMS Group
Hewlett-Packard Company
Mark.Gorham@hp.com

Appendix K - HP CSS Applications Options Review External

Newfoundland Power

Customer Service System (CSS) Application

Options Review

Abstract: The purpose of this document is to provide a review of the options available for Newfoundland Powers mission critical Customer Service System (CSS) application.

Prepared for:
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Version V1.0 – April 7, 2003

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Preface

Distribution Control	
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HP Services Sales	Scott Smith
Customer Project Manager	
Customer Operations	
HP Customer Services	
Technical Review List	
Change History	
Version	**Date**
Initial Version	

Table of Contents

1. Executive Summary

Newfoundland Power is an investor owned utility whose business is the generation, transmission and distribution of electricity in a regulated environment.

Newfoundland Power and its predecessor companies have been engaged in the production and sale of electricity since 1885. Newfoundland Power, a regulated investor owned electric utility, serves approximately 220,000 customers throughout the island portion of the province of Newfoundland and Labrador.

At the heart of its Customer Services operation is a mission critical application called Customer Service System (CSS). This is an application that has been customized over the years to better address the unique requirements of its Customer base. Among other things, it allows its call center representatives to address all of its service orders, billing and customer calls.

CSS is a COBOL based application that runs on the HP OpenVMS Alpha operating system platform. In recent years the front end client portion has been enhanced with the Axiant 4GL product from Cognos Corporation.

In determining their future strategy and architectures, Newfoundland Power is currently investigating the following options with respect to the CSS application:

1. Port CSS to a new platform (preference *if* this option is chosen is Windows 2000)
2. Keep current environment, but adopt industry standard development and integration architectures and technologies.
3. Replace CSS with a new application

Making a decision to switch platforms for a mission critical application like CSS is never an easy one. Since every OS platform from every vendor has strengths and weaknesses, it is important to weigh the costs and business risks against the benefits that would be achieved in the new environment.

Regardless of the platform chosen, HP can assist Newfoundland Power in developing a future application architecture that will allow them to achieve the following business benefits:

1) Increased business agility e.g. respond to new requirements in shorter timeframes.
2) Protect current investments and minimize both costs and potential future business risks to Newfoundland Power.
3) Drive new business models and direction e.g. provide the capacity to provide partners, customers and employees with secure, real time access to information that they have been previously authorized to access anytime, anywhere – including the internet.
4) Reduce overall costs by simplifying the overall application infrastructure design.
5) Continue to build a highly motivated IT Development and Operations environment by providing them with the latest software development and management technologies

Should Newfoundland Power decide on Option 2 (Section 3), HP would like to recommend an Application Consolidation and Integration workshop be considered as its next step. It would be a way to not only protect its current investments, but also enhance its current environment with new application development, management and integration technologies.

Section 5 “Future Vision” is also provided as part of this report so that Newfoundland Power can better understand where the industry is heading with respect to IT Strategies and Architectures.

2. Current Environment

This section will provide a summary[1] of Newfoundland Powers current environment for the CSS application.

2.1 Application Configuration - Online Environment

CSS is a thin client environment where almost all business logic is executed on the server. It is comprised primarily of Cognos Axiant on the PCs and Powerhouse with calls to Cobol "back-end programs" on the server for primary business logic execution.

CSS has a graphical user interface with a windows like environment. It is a modular application with like functions grouped under series of screens called "Conversations"

It is integrated with Call Center Software from Aspect Telecommunications. There is Screen Pop capabilities and automatic call routing to Customer Account Representatives

The application contains direct access to a database of a separate outage management application from within CSS. The outage management application is PCLS - *Problem Call Logging System.*

2.1.1 Custom Software

The following is a description of some of the customized software associated with the CSS application online environment.

Desktop:	▪ Cognos Axiant 3.0. Utilizes some proprietary windows objects. ▪ Visual Basic module for specific screen handling technique
Server:	▪ Powerhouse for VMS Version 820.d3. ▪ Cobol

2.1.2 Embedded Software

The following is a description of some of the embedded software associated with the CSS application:

---

[1] Material supplied by the IT Staff at Newfoundland Power.

- PC Lookup Correction v1.10 from COMDATA Services Ltd. Software to ensure mailing addresses comply with Canada Post standards to obtain postal incentive rates.
- Communication with a number of windows software programs is enabled via DDE (Dynamic Data Exchange). This includes Microsoft Excel, Visual Basic program and integration with Aspect system (Screen Pop). No OLE, ActiveX, custom DLL's

2.1.3 Response Time and Availability

Response Time: The majority of on-line forms have a sub second response time. Specific "heavy" functioning forms could have a response time up to 4-6 seconds at times.

Availability: The on-line availability is approximately 99 %. And runs in update mode from 8:00 am to 8:00 pm Monday to Friday with extended read-only capabilities available outside this window.

2.2 Batch Environment

The batch processing is performed to complete high volume transactions and larger reporting requests. (e.g. post readings, post cash payments, edit accounts, calculate late payment charges, calculate forfeited discount charges, calculate bills, print bills, perform audit checks, populate collection queues, issue form letters, produce daily, weekly and monthly reports etc.)

There is a regular nightly batch "window" (8pm - 8am daily) during which full online system availability is limited. As well there are weekly, monthly, quarterly, yearly and numerous specialized processes. Nightly and most other batch processes are computer operator attended.

2.2.1 Custom Software

The following is a description of some of the software associated with the CSS application batch environment.

- OpenVMS Cobol 2.4
- ProCOBOL
- Powerhouse QUIZ, QTP
- DCL - used for job submission, execution control, printing and error handling

2.2.2 Embedded Software

The following is a description of some of the embedded software associated with the CSS application.

- PC Lookup Presort v1.04 from COMDATA Services Ltd. Software to sort mail to obtain postal incentive rates.

2.2.3 Batch and Printing

The following provides an overview of the batch and printing availability times.

Full batch window length: 10hrs and 20min.

This is from the start of the first job to the last read-only report each day. The online system is made available much sooner however the system response time is often too degraded for general call center use till full batch is completed. If the full batch window goes beyond the 8:00am start time for call center opening some read only jobs are sacrificed to ensure performance is maintained.

The following provides an indication of the amount of printing done:

Bills Printed:

- 192,000 bills are printed per month.
- This averages to 10,100 bills printed per night assuming a 19 cycle billing period. There are on average two nights per month (non-reading days) where less than 3,000 bills are printed.

Collection Notices and Form Letters:

- 14,600 Payment Reminder Notices are printed per month. About 730/day.
- 10,500 Delinquent Account Letters are printed per month. About 525/day.
- 1,400 Various form letters are printed per month.

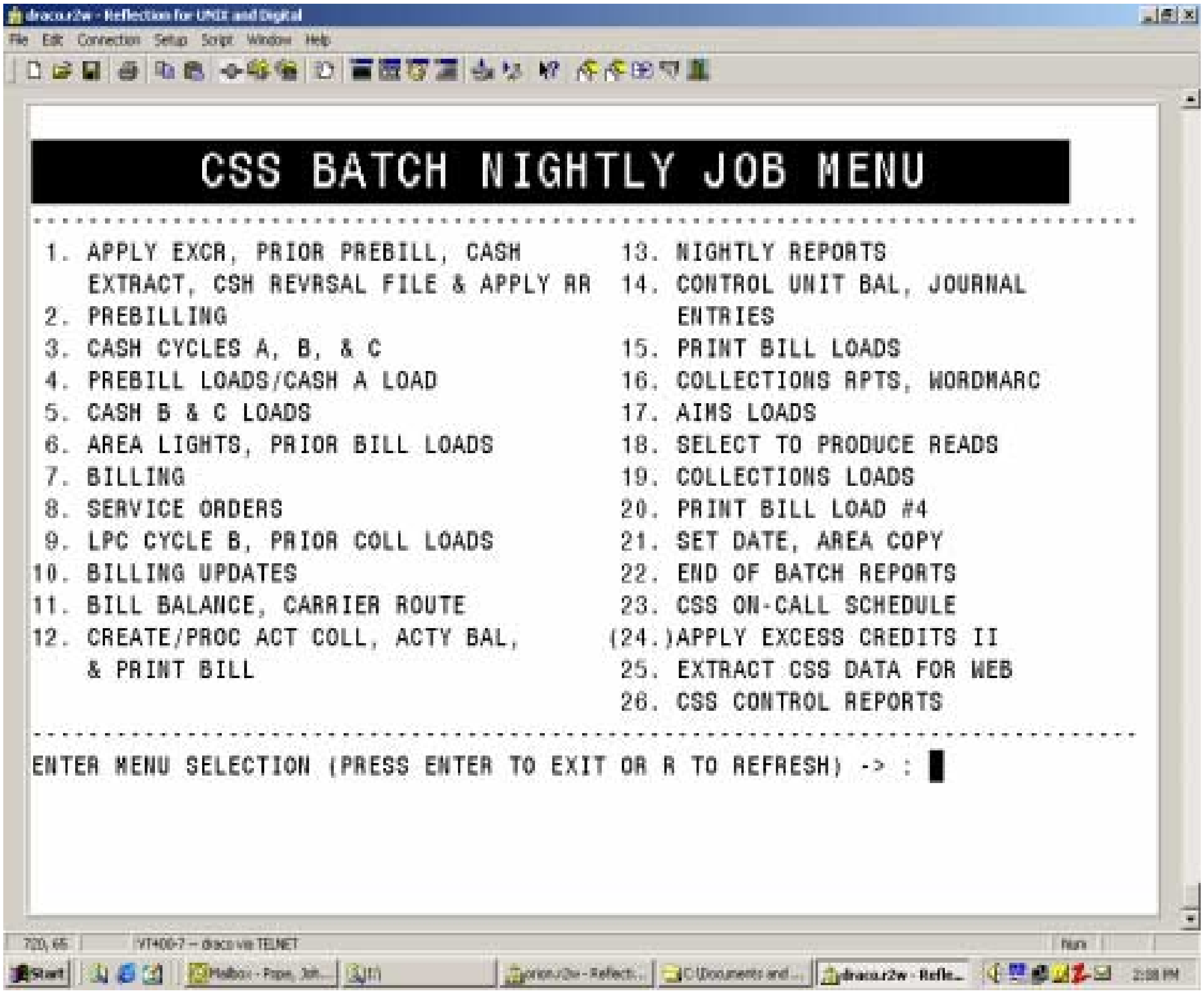
Transactions Posted:

- 121,500 cash transactions are posted per month. About 6,100 per day.
- 205, 000 readings are posted per month. About 10,800 per cycle day.

The following screen shot depicts the batch submission menu that is utilized by the operator to execute the CSS nightly batch. The batch operator interface is text based written in DCL and running on the OpenVMS operating system. The operator logs into the

DRACO server with a privileged account and executes the batch steps in a pre-determined sequence (not necessarily in numerical order). Each of the batch options can/may submit multiple jobs to be executed.

Figure 1 CSS Batch Nightly Job Menu



```
                  CSS BATCH NIGHTLY JOB MENU
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
 1. APPLY EXCR, PRIOR PREBILL, CASH       13. NIGHTLY REPORTS
    EXTRACT, CSH REVRSAL FILE & APPLY RR  14. CONTROL UNIT BAL, JOURNAL
 2. PREBILLING                                ENTRIES
 3. CASH CYCLES A, B, & C                 15. PRINT BILL LOADS
 4. PREBILL LOADS/CASH A LOAD             16. COLLECTIONS RPTS, WORDMARC
 5. CASH B & C LOADS                      17. AIMS LOADS
 6. AREA LIGHTS, PRIOR BILL LOADS         18. SELECT TO PRODUCE READS
 7. BILLING                               19. COLLECTIONS LOADS
 8. SERVICE ORDERS                        20. PRINT BILL LOAD #4
 9. LPC CYCLE B, PRIOR COLL LOADS         21. SET DATE, AREA COPY
10. BILLING UPDATES                       22. END OF BATCH REPORTS
11. BILL BALANCE, CARRIER ROUTE           23. CSS ON-CALL SCHEDULE
12. CREATE/PROC ACT COLL, ACTY BAL,      (24.)APPLY EXCESS CREDITS II
    & PRINT BILL                          25. EXTRACT CSS DATA FOR WEB
                                          26. CSS CONTROL REPORTS
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
ENTER MENU SELECTION (PRESS ENTER TO EXIT OR R TO REFRESH) -> : █
```

2.3 Data Architecture

The current data model for CSS is fully documented and is based on a Customer/1 model, which was highly customized when the system was developed. The separation of Customer, Premise and Bill Account is preserved. The data is relatively normalized and modeled accordingly.

With few exceptions all customer related data is stored in one Oracle database residing on an OpenVMS server. OpenVMS RMS files are primarily used to hold interim transactional data, control data and some reporting information and as well to load database tables during batch processing.

The following section provides additional details of the data architecture for the CSS application and associated interfaces.

2.3.1 Database Management System

The following provides an overview of the databases used at Newfoundland Power.

1. The primary customer related CSS application data is stored in an Oracle 8.1.6 database (SID: CSSPRD) residing on an OpenVMS V7.2-1 server.
2. Oracle SQLNET protocol is used for all client connections (TNSNAMES).
3. Oracle Server Standard edition 8i (8.1.6.1.2, 8.1.7.0.0) on Windows NT 4.0
    a. Corporate Reporting: Data-marts for financial and HR
    b. DataStream MP2, Avantis.PRO
    c. URM Safety Management System
    d. Customer Inquiry database for Internet, Intranet and IVR
4. Oracle Server Standard edition 8i (8.1.7.3.0) on Windows 2000
    a. ITRON Premier 4 Plus (Handheld Meter Reading)
5. SQL Server 7.0 Standard edition on Windows NT 4.0
    a. Intranet content storage
    b. Plant (Fixed Assets)
    c. Operations
    d. Forms

6. SQL Server 2000 Standard edition on Windows 2000
    a. Microsoft Great Plain's Enterprise (GL/AP/AR/Canadian Payroll/Project Accounting/Inventory/Purchasing)
    b. Microsoft Great Plain's Empower (Human Resources)
7. Workstations currently have one of several versions of the Oracle client installed including v7.3, v8.0.5, and v8.1.6.

2.3.2 Database Tuning and Monitoring Tools

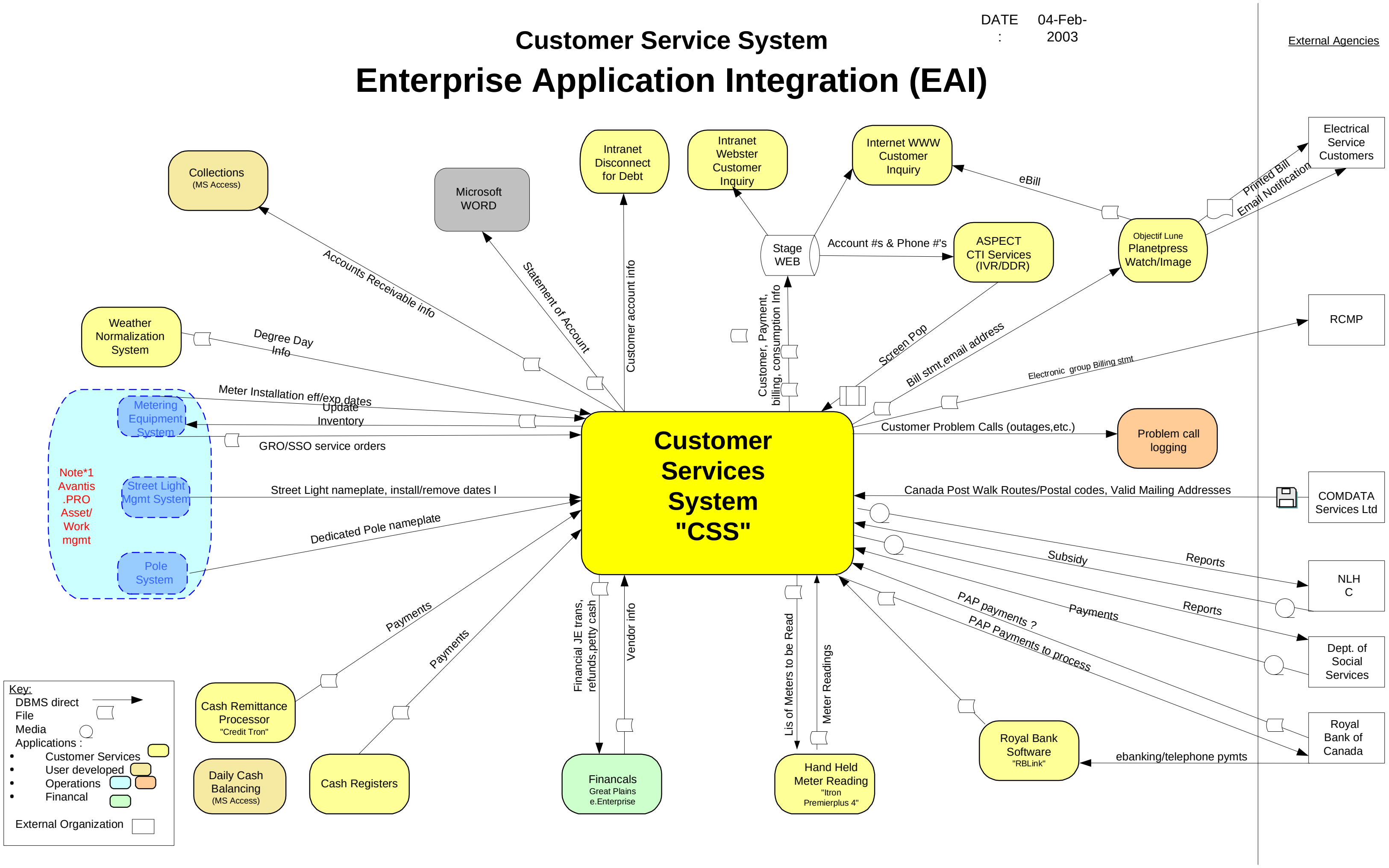
The following provides an overview of the database backups, file systems and users.

- **Database Backups**: In-house written DCL procedures utilizing OpenVMS operating system features.
- **File System**: Data of an adhoc, reporting, and batch processing nature is stored in the OpenVMS RMS file subsystem. The RMS files are formatted for sequential or indexed access.
- **Users**: 250 - 300 named users; 70-80 concurrent users daily; peaks at 100
- **Database size**: 26 gigabytes; Grows at about 2-3 gigabytes of data per year Annually purge 2.5 gigabytes of data
- **Database Reserved Memory**: 1.438 gigabytes

2.3.3 CSS Application Interfaces

Reference Figure 2 for a diagram that illustrates the CSS Application interfaces.

Figure 2 CSS Application Interfaces



2.4 Security Architecture

Multi-level security features have been developed to prevent unauthorized access at the business or database level. These include application, DBMS and Operating System level security.

2.4.1 Application Level

The CSS application has security features built in through code. It has security tables set up in the database that define functional groups and the individual screens that are accessible to the group. An administrator assigns users to a group. This is a function within the application.

Code is written to identify the user logged in and the group they belong to. This is maintained throughout the session. As the user navigates from screen to screen common code is executed to ensure the user can access the particular form. If not authorized a message is presented to the user as notification that access is denied.

2.4.2 Database Security

Application level database security is enforced thru the operating system using trusted connections.

Oracle table level security is enforced thru Oracle password protected roles.

Database views are used as a security technique to protect sensitive data.

2.4.3 File Security

Controlled with OpenVMS identifiers. The identifiers are granted during application start-up and are only available while running the application. If access is required outside the application a separate identifier is assigned to the user and this is restricted based on the users requirements.

2.4.4 Operating System Security

Usernames and passwords are required to access all systems. The user name and password is validated and based on the users specific access is given via vms identifiers. This sets the level of access allowed on the system.

2.5 Reporting Environment

This section will provide an overview of the various reporting features currently available in CSS.

2.5.1 Production Reporting

Production Reporting is basically handled through the on-line environment and through the nightly batch processing. Reports are developed through quiz and Cobol and are executed in a structured scheduled manner.

CSIS - A small reporting application written in DCL called CSIS. This basically consolidates some of the production reports, generated primarily through batch, into a central area for users. The menu has various options which print the pertinent report based on the users logon id.

2.5.2 Ad Hoc End User

CSS does not have a reporting database or warehouse available to users. All reporting is generally done from the production data source.

The DR/Test server Corvus is used for some reporting efforts as this takes pressure from the production machine and allows the users some flexibility in when and how the reports are developed and executed. Restoring the production CSS database over to the test machine as required facilitates this.

Ad Hoc reporting is available to users through 2 different avenues.

Quiz is primarily used as the ad-hoc tool of choice. Users are familiar with the tool and what is available through the dictionary.

Impromptu (Cognos report writer tool) is also utilized in a limited means. Some users are skilled in generating and executing Impromptu reports.

2.5.3 OLAP Reporting

Cognos PowerPlay is the product used for OLAP reporting.

An OLAP cube is created from daily revenue files generated from the nightly batch processing for billing/revenue analysis.

2.6 Hardware

This section provides an overview of the current hardware environment.

2.6.1 Production

Production Application/Database Server (DRACO):

- Type Compaq Digital Alpha Server 4100
- Processor: 3 5/533
- Memory: 6 Gb Ram
- Disks: Internal 7 @ 9GB 1@ 18GB 3 @ 4.3GB SAN 18@36.4GB
- Controller: 1 SE SCSI, 2 FC Controllers, 1 Raid KZPSC 1 DE500 10/100 Ethernet
- Tape Drive: TZ88, 2 DLT 7000

Disaster Recovery and Test

Disaster Recovery Server / Test Server (CORVUS)

- Type Compaq Digital Alpha Server 4100
- Processor: 3 5/ 533
- Memory: 6 Gb Ram
- Disks: Internal 8 @ 9GB 1@ 18GB 1 @ 4.3GB
- SAN 18@36.4GB
- Controller: 1 SE SCSI, 2 FC Controllers, 1 Raid KZPSC 1 DE500 10/100 Ethernet
- Tape Drive: TZ88, 2 DLT 4000

2.6.2 Development and Test

Development Server/Test (ORION)

- Type Compaq Digital Alpha Server 4100
- Processor: 2 5/ 300
- Memory: 1.5 Gb Ram
- Disks: 17 @ 9 Gb, 1 @ 4Gb total 157Gb
- Controller: 1-10/100 ETH,2 SE SCSI, 1 Raid KZPSC 1 DE500
- Tape Drive: 1 @ TZ88, 1 @ TZ87

2.6.3 Desktop Configuration

- Platform/OS: Windows NT
- Type: Dell Optiplex GX110+/L Pentium III
- CPU: 733
- Hard Drive: 12.4 gigs
- Monitor: 17 inch Dell Monitor
- Memory: 256 MB

3. Target Environment Options

In determining there future strategy, Newfoundland Power is currently investigating the following options:

1. Port CSS to a new platform (stated preference *if* this option is chosen is Windows 2000)
2. Keep current environment, but adopt industry standard development and integration architectures and technologies.
3. Replace CSS with a new application

Regardless of the decision on which platform(s) it decides is the way forward HP is a multi-platform company that can assist Newfoundland Power to fast-tack them to achieving their desired end state.

This section will provide some thoughts for consideration by Newfoundland Power as they go through the process of determining their future plans.

The goal of the following sections is to ensure Newfoundland Power takes into consideration all of the issues and technical considerations when determining their future IT Architecture.

3.1 Overview

Making a decision to switch platforms for a mission critical application like CSS is never an easy one. Since every OS platform from every vendor has strengths and weaknesses, it is important to weigh the costs and business risks against the benefits that would be achieved in the new environment.

The following sections will discuss a few of the platform options that are available to Newfoundland Power.

3.2 Option 1 - Port CSS to New Platform

HP was requested by Newfoundland Power to investigate some ball park estimates of other large application porting estimates and what it might cost to port CSS to either Microsoft Windows or one of the various UNIX environments.

The HP porting centers typically require a 1-2 day on site code analysis and workshop with the Customer in order to provide a detailed estimate, but the following “rule-ofthumb" (application only) for a typical large mission critical application came from an experienced developer in one HP porting center:

- $1 per line of code if the code is fairly straight forward, is based on industry standards (Fortran, COBOL etc) and has minimal optimization for a specific hardware platform.
- $4-$10 per line of code if the code has a high degree of complex work flow, or is heavily customized to take advantage of the current hardware / software environment.

3.2.1 Sample Case Studies

From HP porting center experiences:

Example 1 - Customer had approximately 1.3M lines of customized COBOL. Was moving from HP e3000 to HP-UX (UNIX "like" to UNIX). Resource effort was 20 engineering years that was estimated to take 11 months based on Customer requirements. Using a mix of off-shore and on-site development resources, the application porting cost on its own was Cdn$3M (no hardware, third party products or training and documentation costs included).

Example 2: Customer had approximately 1.5M lines of COBOL and was moving from OpenVMS VAX 32bit environment to the OpenVMS Alpha 64bit environment. Effort was approximately 2 full time resources for a period of approximately 6 months. Cost was Cdn$620K (no hardware, third party products or training and documentation costs included).

Example 3: Customer had extensively customized VAX DIBIOL environment with approximately 1M lines. They wanted to move this application to Tru64 UNIX on Alpha. Biggest issues was moving their DIBOL code to a third party product and dealing with printer and LAT communication issues. Cost was approximately 1 Engineer year of effort.

3.2.2 Platform Switch Considerations

Typical items for consideration when deciding to switch platforms are:

1. Total Costs
    a. Application porting and/or new application costs

  b. Customizations required in order to maintain current business commitments and service level agreements.
  c. Training of not only IT Staff, but also end users, partners and potential Customers as well if any changes in business flows are required.
  d. New hardware that includes servers (production, development and disaster recovery), storage, tape drives, tape media (if different from current environment)
  e. Third party software license, support and maintenance costs

2. Business Risk
   a. A platform switch may mean that fewer IT staff resources are available to handle current day-to-day support and enhancement requirements. Even if the hard coding is done by external vendors, existing IT staff needs to be involved to ensure business logic is implemented correctly.
   b. While a technical view might simply look at lines of code to provide baseline estimates, one of the biggest area's often overlooked in any platform switch is the effort required to ensure the current work flow is emulated in the new environment. This is often an issue as it might mean re-writing entire sections of business logic from scratch and this means critical interfaces to external systems might also need to be changed, or at the very least, extensively tested.
3. Application Complexity:
   a. How much customization is there in the current environment that would need to be rewritten and/or re-architected in the new environment e.g. DCL lines of code, security identifiers specific to OpenVMS etc.
   b. Newfoundland Power is currently running on a 64bit HW/OS platform. 64bit or 32 bit target platform is a consideration that a Customer needs to consider in their migration decision.
   c. Big-endian vs. little-endian. Binary and RMS files need to move to some kind of ISAM or relational DB when migrating to Unix. Binary files will either need to converted to the new Endian format or marshalled into/out of the other Endian machine.

   d. How much customization is there? Samples within Newfoundland Power might include the OpenVMS DCL based batch processes, backup procedures and end user reporting processes.

4. Security: In today's world, the issue of security and viruses has become a matter of much higher importance than in the past. These issues must now be considered as part of any platform decision.
5. Availability: With Internet based services being offered by many companies today, the need for high availability and application stability is becoming much higher than it ever was in the past. These issues must now be considered as part of any platform switch decision.

3.3 Option 2 – Improve Current CSS Platform

As part of this review, one of the items under consideration was "if we stay with OpenVMS as the primary platform for CSS, what changes could Newfoundland Power make to improve the current environment to better meet future business requirements?"

To meet this request, the following section provides a few items for consideration.

3.3.1 Adopt Industry Standards for Development and Integration Technologies

There are two main strategies for Web Services and new application frameworks that are emerging today - .Net (Microsoft) and J2EE (IBM, HP, Sun, Oracle, SAP, PeopleSoft etc).

The key message being promoted by most analysts is that few companies and ISV's are expected to adopt only one strategy. It is felt that a blend of both J2EE and .Net is what most Customers will adopt for their environment. In addition, the adoption of industry standard XML as a data interchange format means that a XML formatted document in the .Net environment will be able to be read cleanly on the J2EE environment.

This option would minimize Newfoundland Power's future risks by focusing a much smaller subset of the time, effort and $'s to adapt its current platform to take advantage of:

- latest technologies like Java (now V1.4 on OpenVMS-latest version in industry). Many Universities are now switching from traditional languages such as C, C++ to Java as it provides the capability to run applications on any platform that supports Java e.g. UNIX, OpenVMS, Windows, Linux. This means that students and/or programmers can write Java applications using PC tools and have them run on OpenVMS, UNIX, Windows, Linux platforms.

- exposing current CSS business logic written in Cobol and other 3GL languages and data via J2EE technologies with products like Bridgeworks (free utility bundled with OpenVMS) .
- Using cross platform data interconnectivity products like Attunity
- Adopting Application Messaging architectures that allows CSS business logic to be seamlessly exposed to the .Net and other J2EE platforms
- Using cross platform tools like job schedulers, backup etc.
- Upgrading Oracle to 9i to take advantage of latest J2EE technologies
- Consider an active-active cluster with Oracle 9i RAC for increased availability when CSS hours of availability start increasing. This might include a disaster tolerant cluster which allows for things like continued availability - even in the event of a datacenter fire.

3.3.2 Adopt Cross Platform Management Technologies

Newfoundland Power should consider management solutions that support different platforms, so even if their platform changes in the future, their management tools do not have to. A few examples of this would include event notification, batch / job schedulers, backups, security auditing and monitoring, performance and capacity planning, console management etc.

Here are a few sample products:

1. ISE - scheduler and backup
http://www.i-s-e.com/Products/EnterpriseSCHEDULE/enterpriseschedule.htm
http://www.i-s-e.com/Platforms/OpenVMS_Software/index.html

2. OSYRP - Dollar scheduler (see attached press release that discusses a partnership with Appmind (OpenView Agents) and OSYRP Scheduler partnership.)
http://www.orsyp.com/
http://www.orsyp.com/software_dollar_universe.asp

3. Advanced Systems Concepts - ActiveBatch
http://www.advsyscon.com/
4. MVP Systems - JAMS Scheduler:
http://jams.argent-software.com/

5. OpenView Enterprise Management - During earlier conversations with Newfoundland Power, there was also some concern raised about OpenView and its capabilities to manage OpenVMS systems. Something that might be of interest is the following announcement from a partner ISV that came out a few weeks ago. It discusses OpenView management of a number of mission critical OpenVMS systems.

http://www.appmind.com/under.asp?menu=2&msgType=1&msgID=57

(March 3, 2003) "...The initial result of the partnership between HP and Appmind Software is a deal with a Financial Information Company in France. The customer has taken a decision to buy HP OpenView to monitor their diversified IT environment where the most business critical systems are based on OpenVMS..."

3.3.3 Adopt Security Architecture Based on Industry Standards

Future corporate security planning and architecture should include cross platform, industry standard LDAP / directory based schemes that provide the capability to have a single profile for all users on all platforms.

Note that this does not necessarily mean SSO (single sign-on), but rather RSO (reduced sign-on) as applications typically need time to migrate to new security strategies.

3.4 Option 3 - Replace CSS with New Application

While beyond the scope of this report, apparently Newfoundland Power reported that this cost was estimated to be in the $8-10M range. It is not clear if these costs also included items like:

- New server hardware including storage, servers and tape media capable of also being able to access and restore the current historical data that might be required for business or legal reasons.
- Operating System and layered products
- Third party support packages costs
- Disaster recovery estimates (servers, software, facility) for the new environment

4. HP OpenVMS Roadmap and Testimonials

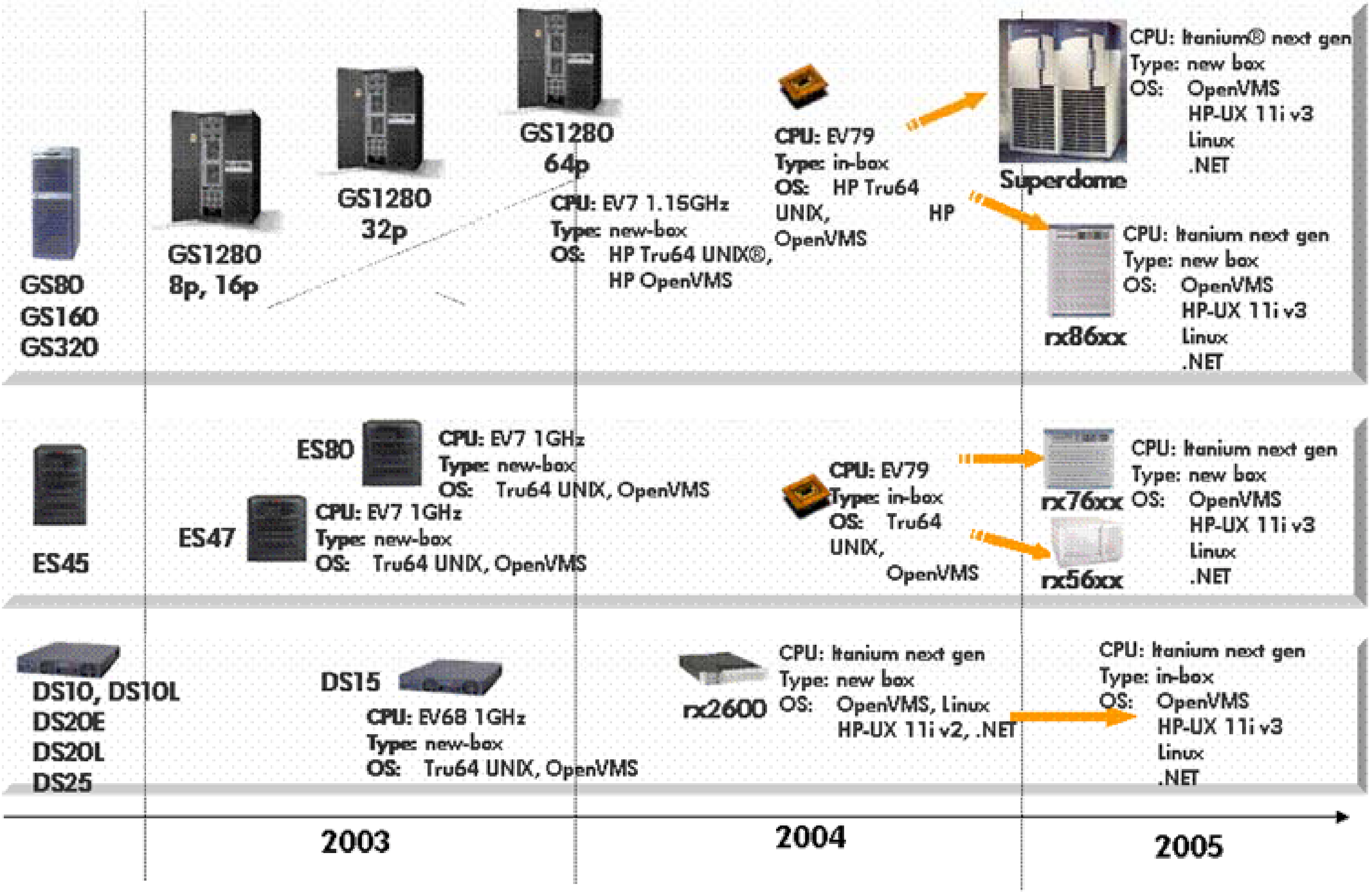
HP OpenVMS Alpha is a 64-bit multitasking, multiprocessing virtual memory operating system. Current implementations run on Alpha systems from HP, and other vendors.

Work to port OpenVMS to systems based on the Intel IA-64 architecture and specifically to the Itanium Processor Family is presently underway. Reference Figure 3 for a roadmap for OpenVMS futures.

The following is a list of recent OpenVMS testimonials from Customers and ISV Partners:

1. Cerner (Health Care)
   http://h71000.www7.hp.com/openvms/brochures/cerner/cerner.pdf
2. Commerzbank 9/11 Disaster (Bank – Financial)
   http://h71000.www7.hp.com/openvms/brochures/commerzbank/commerzbank.pdf
3. Dartmouth Medical Center (Health)
   http://h71000.www7.hp.com/openvms/brochures/dartmouth/dartmouth.pdf
4. Hydro Quebec (Power Generation and Distribution)
   http://h71000.www7.hp.com/openvms/brochures/hydroquebec/
5. India Railways (Transportation)
   http://h71000.www7.hp.com/openvms/brochures/nz_steel/nz_steel.pdf
6. SouthEastern Freight (Transportation)
   http://h71000.www7.hp.com/openvms/brochures/southeastern/southeastern_freight.pdf
7. New Zealand Steel (Manufacturing)
   http://h71000.www7.hp.com/openvms/brochures/nz_steel/nz_steel.pdf
8. HP OpenVMS Brochure:
   http://h71000.www7.hp.com/openvms/brochures/openvms_brochure.pdf

Figure 3 HP OpenVMS Roadmap



5. Future Vision

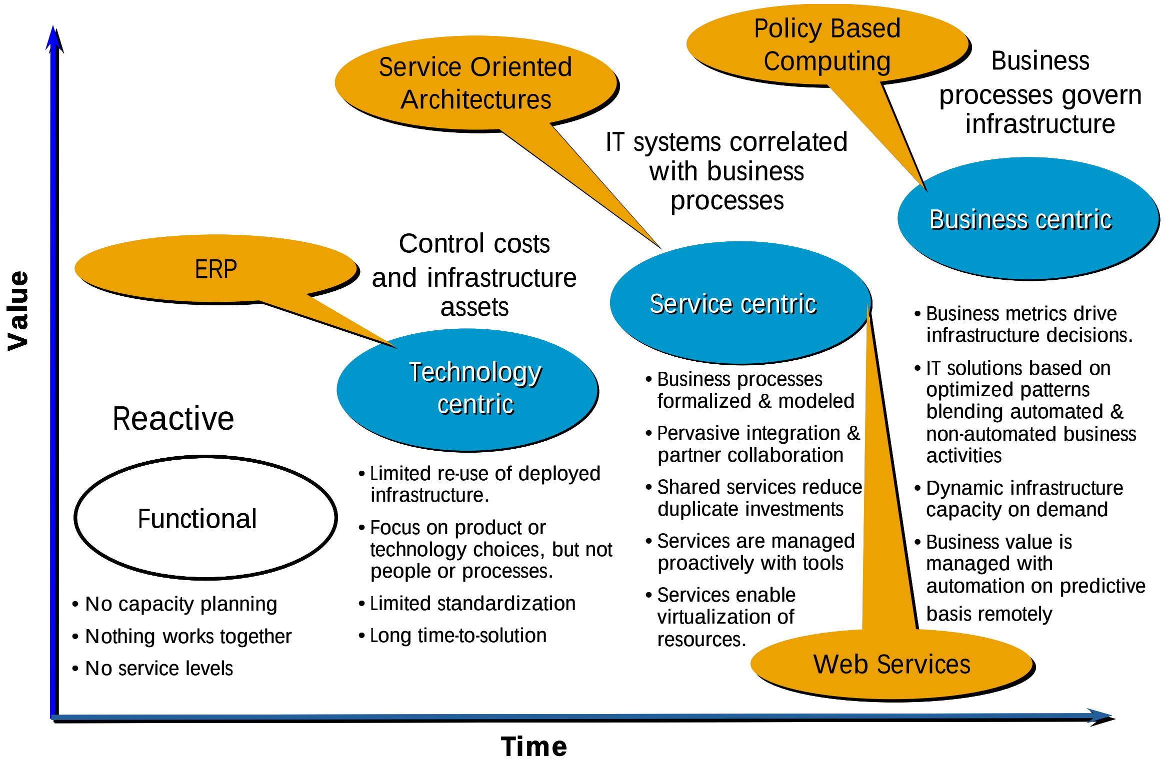
Regardless of the platform chosen, HP can assist Newfoundland Power in developing a future application architecture that will allow them to achieve the following business benefits:

1. Increased business agility e.g. respond to new requirements in shorter timeframes.
2. Protect current investments and minimize both costs and potential future business risks to Newfoundland Power.
3. Drive new business models and direction e.g. provide the capacity to provide partners, customers and employees with secure, real time access to information that they have been previously authorized to access anytime, anywhere – including the internet.
4. Reduce overall costs by simplifying the overall application infrastructure design.
5. Continue to build a highly motivated IT Development and Operations environment by providing them with the latest software development and management technologies.

HP has developed its Adaptive Application Architecture (AAA) to help Customers meet these business agility challenges. AAA is a set of methodologies, processes and services that enables organizations to redesign application infrastructure using software as a service to increase business agility. Reference Figure 4 for a description on how to achieve future business agility.

The goal of AAA is to increase efficiency in application development and management, improve architectural design, increase operational excellence, and integrate agility metrics that provide investment justification for IT improvements.

Figure 4 The Journey to Achieve Business Agility



- No capacity planning
- Nothing works together
- No service levels

- Limited re-use of deployed infrastructure.
- Focus on product or technology choices, but not people or processes.
- Limited standardization
- Long time-to-solution

- Business processes formalized & modeled
- Pervasive integration & partner collaboration
- Shared services reduce duplicate investments
- Services are managed proactively with tools
- Services enable virtualization of resources.

- Business metrics drive infrastructure decisions.
- IT solutions based on optimized patterns blending automated & non-automated business activities
- Dynamic infrastructure capacity on demand
- Business value is managed with automation on predictive basis remotely

One of the main components of AAA is the adoption of Web Services (J2EE, .Net) and other web enabling technologies. The concept of Web services is the beginning of a new service-oriented architecture designed to build and integrate future software applications.

The HP Adaptive Application and Integration Workshop provides a methodology to assess Newfoundland Power's IT environment and map out a new Service Oriented Architecture (SOA) application architecture and strategy.

Additional details can be provided on request from Newfoundland Power.

Appendix L - Oracle Commitment Information External

ORACLE
Oracle Corporation
500 Oracle Parkway
Redwood Shores
California 94065
phone 650.506.7000
fax 650.506.7200

July 11, 2003

Peter Collins
Manager of Information Services
Newfoundland Power
Mailing address:
P.O. Box 8910
55 Kenmount Road
St. John's NL
A1B 3P6

Dear Mr. Collins

Thank you for your recent inquiry regarding Oracle’s roadmap plans for HP OpenVMS Alpha. I believed the attached Statement of Directions should assist you in you project planning strategy. If you have any follow up questions or concerns, please don’t hesitate to send me a note directly.

Sincerely,

Sandy Vella
Director, Product Management HP Operating Systems
Platform Alliances
Oracle Corporation

ORACLE

Statement of Direction

Oracle for HP Alpha OpenVMS

June 2003

ORACLE'S COMMITMENT FOR OPENVMS

Oracle and HP have a long and successful history of delivering enterprise solutions to the OpenVMS marketplace for more than 20 years. The OpenVMS port remains one of Oracle's top platforms, with a large and loyal customer base. Oracle is committed to providing continued ports of its core database to OpenVMS. In fact, the next major Oracle RDBMS version is currently being ported to OpenVMS Alpha. Oracle will also be focusing on faster product delivery time (within 90 days of base release) and as always product quality on OpenVMS. Support for the next major Oracle RDBMS version on OpenVMS Alpha will be provided in accordance with Oracle Standard and Extended Support policies – at least until 2009.

PRODUCT DIRECTION & STRATEGY

Oracle continues to work very closely with HP to ensure as HP rolls out new systems and operating system versions, Oracle is certified and optimized to run on those products.

HP has announced plans to consolidate its 64-bit servers on the Itanium Processor Family. Oracle and HP are working very closely on a migration strategy and solid solution offerings for OpenVMS customers.

PRODUCT AVAILABILITY

The following products are currently available in production on HP Alpha OpenVMS:

- **Oracle8i OPS Release 3 (8.1.7) with Very Large Memory (VLM)**
- **Oracle9i RAC Release 1 (9.0.1) with VLM**
- **Oracle9i RAC Release 2 (9.2) with VLM**
  - RMAN
  - Oracle HTTP Server powered by Apache
  - Context Cartridge
  - Spatial Data Cartridge
  - Image Data Cartridge
  - Parallel Query Option
  - Parallel Server Option with Oracle8i
  - Real Application Cluster with Oracle9i
  - Distributed Database Option
  - Advanced Networking Option
  - Advanced Replication Option
  - Partitioning Option
  - Object Option
  - Pre-Compilers
  - C/C++, COBOL, Fortran
  - Network
    - TCP/IP
- **Oracle Applications Release 11.0.3**
- **Oracle Applications Release 11i backend support**

Oracle9i Release 2 (9.2) has been certified on OpenVMS 7.3, 7.3-1, 7.3-1_EV7-V0100. Oracle and HP will jointly certify future versions of OpenVMS as they become available with compatible versions of Oracle OpenVMS products.

For more information, please send email to *infodec@us.oracle.com*.

Oracle Corporation
World Headquarters
500 Oracle Parkway
Redwood Shores, CA 94065
USA

Worldwide Inquiries:
415.506.7000
Fax 415.506.7200
http://www.oracle.com/

To offer our customers the most complete and effective information management solutions, Oracle Corporation offers its products, along with support, education, and consulting, in more than 90 countries.

Appendix M - Cognos Commitment Information External

COGNOS®

July 28, 2003

Peter Collins
Newfoundland Power
P.O. Box 8910
55 Kenmount Rd.
St. John's NL
Canada
A1B 3P6

Dear Sir:

I would like to bring you up-to-date on the current proposed roadmap for the Cognos PowerHouse suite of tools on the OpenVMS platform. Cognos continues to have many OpenVMS customers running successful applications on the Alpha platform. With the merger of HP and Compaq now fully entrenched it is important that we communicate our product intentions for the OpenVMS platform.

Our long-term strategy is the continued support of Powerhouse/Axiant into the future however we are continuing to monitor industry developments with respect to OpenVMS and evolve our roadmap for OpenVMS accordingly. Cognos is committed to supporting PowerHouse on the OpenVMS operating system as it transitions from the Alpha hardware platform to the Itanium hardware platform. While it is too early to tell what the adoption rate of the new OpenVMS operating system on the Itanium hardware platform will be, our current plan is to have a PowerHouse version available in the 2005 timeframe if not sooner. Therefore to ensure that our existing OpenVMS Alpha customers have time to migrate their applications to the new hardware environment, development support for the existing OpenVMS Alpha platform will continue through to the end of 2006 at a minimum. Our expectation is that beyond 2006 existing customers on Alpha will be able to continue to get product support (questions, workarounds) however development support (defect correction) will be provided only in the newer versions of the product on Itanium.

As we continue to refine our current roadmap for the PowerHouse product suite we will keep you advised with specific dates when they become available. I hope that this brief overview of our roadmap for OpenVMS will keep you a happy loyal Cognos customer.

Sincerely,

Ed Shepherdson
VP, Global Customer Support & Application Development Tools
Cognos Inc.
Ottawa, Ontario
Canada
K1G 4S2
613-738-1440

Ed.shepherdson@cognos.com

Appendix N - META Group Information
External

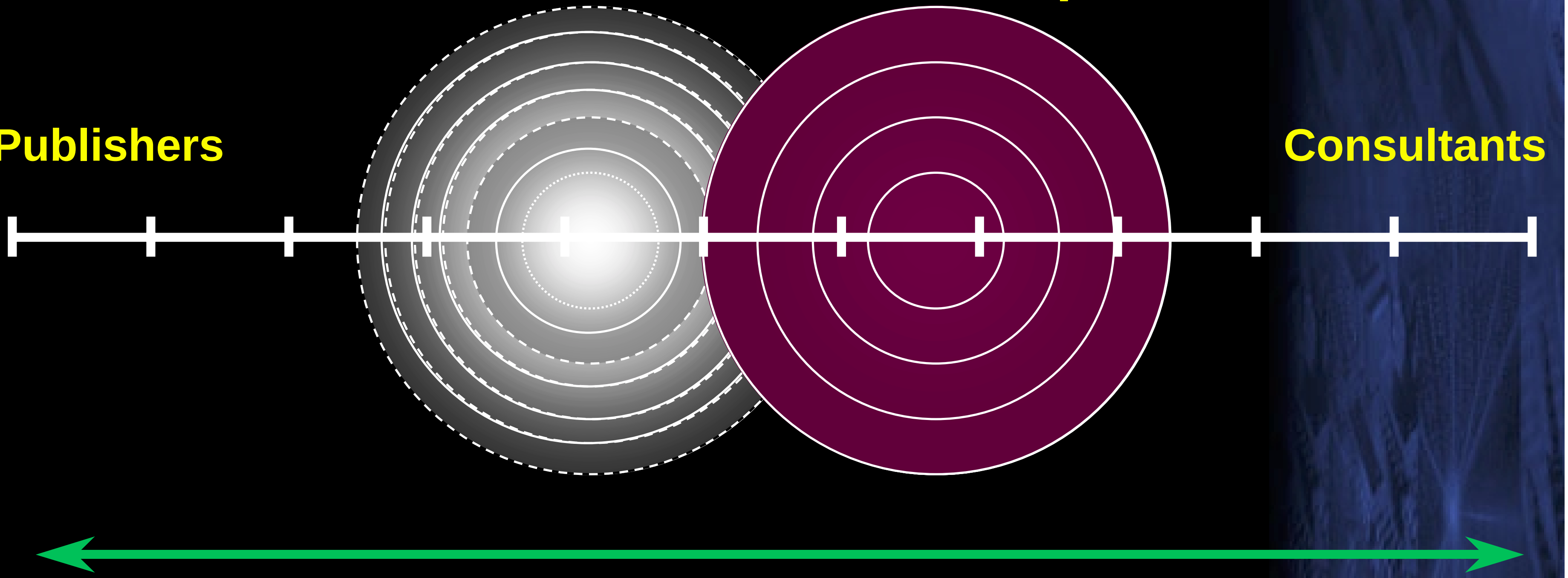
META Group Overview

- **Founded in 1989**
- **$116M (US) in 2002 revenues**
- **Trusted advisor to over 3,600 client organizations**
- **Operations in 34 countries**
- **A Leading Global IT Research and Analysis Provider**
- **META Group hire only SENIOR analysts & consultants (around 250). META Group consultants average more than 17 years of IT problem-solving.**
- **META Group maintains the industry's highest analyst-to-client ratio (50:1, up to 3 to 4 times (and more) better than our competitors). — affording clients more opportunities to speak with our analysts. Our analysts are really available to help you in your projects.**
- ***An Objective, Unbiased, and Vendor-Neutral Stance* - META Group generates unbiased research with a user focus. As a core element of our corporate promise, objectivity is synonymous with our name.**

Profile

- Worldwide reputation: Best strategies, best practices, best methods
- META Group - REAL practice: Architecture, Infrastructure, CRM, Operations Excellence, Security
- META Group unique business model – a customized approach for each client.
- META Group is the only organization in the industry committed to delivering structured methodologies and innovative programs that speed business transformation (Infusion – Structured Transformation Programs)
- Independent Assessment Publications, Retainer Advisory Services, Consulting and Coaching / Training services
- Average of 50% of Revenue back into R&D (e.g. best practices) and client services – The best ratio in our industry!
- Personalized / customized consulting / Rapid and timely knowledge transfer

Market Positioning



Other Providers

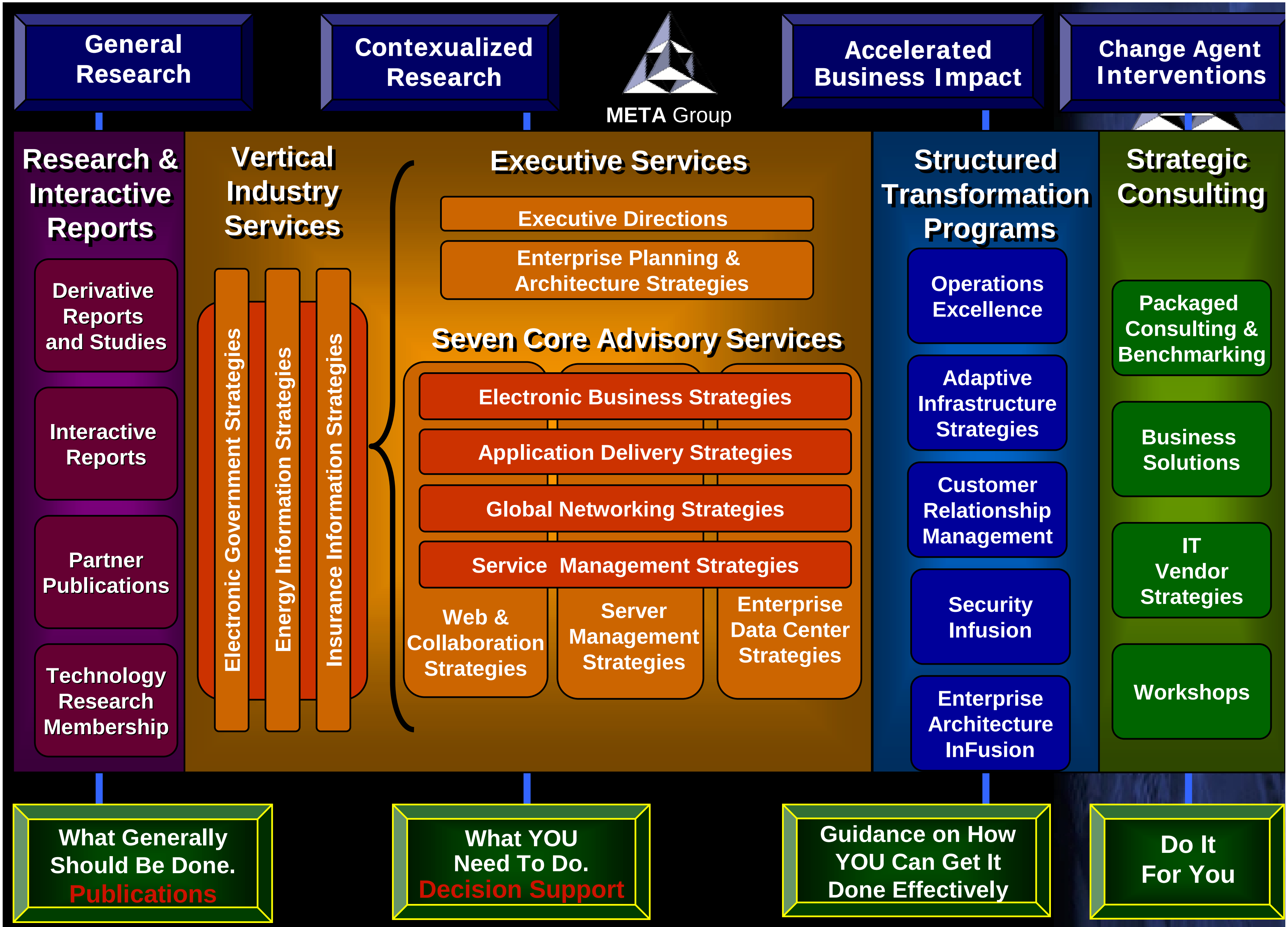
META Group

Publishers

Consultants

Generalization

Customization



General Research

Contexualized Research

META Group

Accelerated Business Impact

Change Agent Interventions

Research & Interactive Reports

- Derivative Reports and Studies
- Interactive Reports
- Partner Publications
- Technology Research Membership

Vertical Industry Services

- Electronic Government Strategies
- Energy Information Strategies
- Insurance Information Strategies

Executive Services

- Executive Directions
- Enterprise Planning & Architecture Strategies

Seven Core Advisory Services

- Electronic Business Strategies
- Application Delivery Strategies
- Global Networking Strategies
- Service Management Strategies
- Web & Collaboration Strategies
- Server Management Strategies
- Enterprise Data Center Strategies

Structured Transformation Programs

- Operations Excellence
- Adaptive Infrastructure Strategies
- Customer Relationship Management
- Security Infusion
- Enterprise Architecture InFusion

Strategic Consulting

- Packaged Consulting & Benchmarking
- Business Solutions
- IT Vendor Strategies
- Workshops

What Generally Should Be Done.
Publications

What YOU Need To Do.
Decision Support

Guidance on How YOU Can Get It Done Effectively

Do It For You

What are infusions?
Definition: Structured Transformation Program

Structured means that we provide a method, direction, and plan on what the client needs to do. In other words, META Group provides a framework to work with us. With proven methods, tools, and dedicated support — enable clients to actively drive organizational change around key business and technology challenges.

Transformation is what the client needs to do. Almost everyone you will talk to will admit that they have to change the way they are doing business, and the balance point is “transforming while performing’’.

Put the Two together, and META Group help companies transform their current organizations by providing a structured ***program*** they can follow to guide them through the change

Structured Transformation Programs: META Group Infusions —

- **META Group's Infusions offer proven methods that enable clients to accelerate and drive change across their organizations. Based on solid program and project management disciplines, Infusions break up challenges into manageable projects, phases, activities, and tasks, focusing on communication to obtain buy-in, demonstrate progress, and articulate value. Integral to the programs are tools, templates, and workshops that accelerate the creation of key deliverables, as well as coaching to educate, provide guidance, and drive progress. Unique product offerings, META Group's Infusions are specifically tailored to help clients "transform while they perform."**

Appendix O- Meta Group Viewing the CIS Market 2002 Edition External

META Group

META Delta

18 September 2002 **File: EIS 255**

Viewing the CIS Solution Market: 2002 Edition

Energy Information Strategies

Zarko Sumic

Deregulation, the main catalyst for customer information system (CIS) market growth, is virtually stalled in North America, driving increased competition among vendors. Low market demand is posing financial challenges for CIS vendors, making vendor viability a primary selection criterion.

The slowdown in deregulation activities in the North American energy market, the negative impact of Enron's demise, and the associated "round trip" trading scandals relating to energy companies' access to capital — exacerbated by the economic downturn — have resulted in low demand for CIS products and have placed additional pressure on CIS vendors.

This year's CIS Conference, held in Baltimore in June, confirmed trends and verified findings published in the 2001 METAspectrum for energy CIS (see EIS Deltas 236, 237, and 239). Low demand has turned the CIS market into a replacement market, with regulated energy companies the only potential customers for CIS vendors. Consequently, vendors are reacting to this change by shifting attention from the unregulated to the regulated market by offering functional extensions for legacy systems (e.g., complex billing, credit and collections) or adding new functionality that can enhance the value proposition for CIS replacements. Users evaluating technology vendors for CIS replacement or extension options must appropriately weigh vendor viability, product ability to meet run-the-business objectives, and vendors' proven ability to execute.

During the deregulation hiatus in the North American energy market (2002-04), low revenues and resulting low R&D investment will force vendors to offer only incremental improvements to existing product lines (e.g., introduction of portals, customer self-service, load/usage/bill presentment). Numerous vendors, after years of unsuccessful attempts to gain traction in the North American market, will cease marketing CIS software products, hoping to find a "safe haven" in the application service provider (ASP) harbor and continue their market presence as customer care and billing business process providers. To address CIS extension market needs and concentrate on customers' tactical requirements to deal with the largest pain point first, vendors will offer a "pseudo-componentized" version of their products (in reality, a partially configured whole product, packaged for a phased implementation). During 2004-06, as more mature deregulation models start to emerge, the CIS market will reaccelerate and provide a growth opportunity to vendors that will weather the market drought. Fueled by increased revenues and improved R&D investment, new truly modular CIS products will start to emerge, leveraging new technology (e.g., Web services) and creating componentized customer care and billing solutions. These new products, designed on service-oriented architecture principles, will enable closer integration within an overall CRM and/or ERP ecosystem, and enable the customer care and revenue cycle business process extension required in transitioning and deregulated energy markets (see EIS Deltas 242 and 244).

META Trend: Faced with a slowdown in deregulation during 2002/03, energy companies will decrease overall CRM spending, focusing on tactical investments in customer information systems and customer interaction centers. As the competitive retail market accelerates during 2004-06, companies will invest in comprehensive operational, collaborative, and analytical CRM solutions.

The 2002 CIS Conference confirmed the following:

- ***Focus on ROI:*** Energy utilities are becoming less willing to make "leap of faith" CIS purchases based on potential soft benefits that can be obtained by top-line (revenue growth) impact of the new CIS (e.g., improve customer acquisition/retention, create new products, reduce time to market). Rather, they are focusing on more tangible bottom-line (cost reduction) impact by improving operational efficiency and customer service efficacy. Due to the still-high CIS replacement cost (regardless of the fact that we have witnessed up to 75% discounting in product licensing due to the low demand), energy executives are seeking hard monetary business-case benefits. Consequently, they are proceeding only where the current system's total cost of ownership is prohibitive (e.g., if the CIS is the only system left on the mainframe), where the cost to modify the existing CIS for a deregulated market far exceeds the replacement cost, or where multiple CISs would result (as in a merger).

- ***Componentization:*** To alleviate customer buying reluctance caused by the perceived high risk and soaring costs associated with the prevalent "big bang" CIS implementation, and to address legacy CIS extension needs, vendors are touting CIS product componentization, which can enable phased implementation or customers to extend the lifetime of legacy systems by addressing the key functional deficiency. Marketed by vendors as the new modular approach, componentization is achieved by partially configuring and packaging a portion of the existing product, rather than rearchitecting/modularizing products using object-oriented design principles. Although a phased execution can successfully address numerous shortcomings of the "big bang" implementation (e.g., easier to manage/control cost, earlier target benefit realization, enabling the "try before you buy" approach), it requires the additional modification of legacy environments and increases product life-cycle and release management complexity. Without fully rearchitected modular CIS products, we see this primarily as vendors' "Trojan horse" selling strategy.
- ***ASPs:*** The nascent customer care and billing hosting market appears to be coming of age, though it is primarily based on the number of vendors offering external service provider (XSP) billing and customer care solutions (see EIS Deltas 229 and 235), rather than the number of CIS outsourcing deals closed in the past 12 months. Similarly, as on the CIS product side, supply significantly exceeds demand. In addition to typical providers (outsourcers — e.g., EDS, SAIC, IGS; utility subsidiaries/joint ventures — e.g., Enlogix, CustomerWorks; vertical solution providers — e.g., Orcom; horizontal retail industry transaction providers — e.g., Alliance Data Systems), we see a host of commercial off-the-shelf product vendors and systems integrators increasingly entering the CIS XSP market. Commercial off-the-shelf vendors are driven either by the desire to wake up a dormant market by creating more attractive financial offerings (e.g., transaction-based licenses booked as O&M expenses rather than upfront capital expenditure) or, in some cases, to lower the entry barrier by mitigating customer technology risk aversion. Less successful product vendors see outsourcing as a way to improve their financials by circumventing GAAP license revenue recognition concerns and minimizing R&D spending by offering "half baked" products in a vendor hosted environment. Systems integrators, in addition to a more traditional post-implementation application support, are steadily moving toward entire business process outsourcing — in some cases, even by acquiring ASP vendors (Accenture Canada/CustomerWorks) to compensate for the lack of implementation engagement due to the market slowdown.
- ***Functional product extension:*** To enhance the CIS replacement value proposition, vendors are extending traditional CIS product functionality to accentuate operational efficiency (e.g., scheduling, self-service, call center productivity, field crew automation, trouble call/outage management) or reduce risk exposure created by energy market volatility (e.g., energy commodity management, load forecasting, nomination). The first trend mirrors a global trend of including order processing and fulfillment in CRM environments, while the second extends CIS focus from revenue cycle management to energy commodity management (load forecasting, scheduling, nomination, aggregation, and settlement) by leveraging metering data already in existence and used in CISs for billing.

Bottom Line

In the slow customer information system market — despite bargain prices — users should proceed carefully with technology partner selection, vigilantly weighing vendor viability with product ability to meet "run the business" objectives and "future-proof" architecture.

Business Impact: During the deregulation hiatus, energy companies should re-evaluate their retail strategy and, accordingly, make appropriate decisions to replace or extend legacy customer information systems. Selected products must offer gradual implementations and provide multiple deployment options.

Appendix P - Microsoft Newfoundland Power CCS Migration Analysis External

Microsoft Consulting Services

Newfoundland Power CCS Migration Analysis

April, 2003

Table of Contents

Overview

The purpose of this document is to provide insight and options for Newfoundland Power to assist with the migration of the CSS application. This application is responsible for all account billing and customer call center inquiries for NF Power and as such is critical to their daily operation and revenue billing cycle. This system is presently implemented using 10-15 year old technology, some of which is at the end of its support life cycle.

At present, the application is stable and running on an HP VMS server using a number of technologies to provide required functionality. The billing and account reconciliation process is implemented using an extensive batch processing system developed using COBOL programs, Cognos Powerhouse programs and VMS DCL Scripts. The customer call center portion of the application is implemented using Powerhouse and Axiant On-line screens and COBOL external programs. In both cases, Oracle Server is used as the backend database. Given the lifecycle of the technologies used in CSS, there is a lack of available skill sets in the industry. , When additional support is required, external resources and consulting firms are not able to provide resources in a timely and cost effective manner. In addition, the ramp-up time and training investment for new employees who have not been previously exposed to the system is significant compared to more currently supported platforms.

NF Power is investigating the migration of this application for the following reasons:

1. CSS is critical to the success of Newfoundland Power
2. Most of the business logic has been custom developed and does a good job o reflecting Newfoundland Power’s current business rules
3. The current platform is getting closer to end of life making future support difficult.
4. External resources to work on the platform and application are not readily available or cost effective.

Given the size, complexity of the processes and previous investments in CSS,, it would be too risky and too costly to re-develop the system from scratch. In addition, several vendors are available which specialize in the migration of the technology in CCS to newer, more mainstream platforms.

Microsoft was engaged by Newfoundland Power to help them investigate options for migrating this system to technology, which will be supported well into the future, as well help them to move into more mainstream support and skill sets. In order to leverage Newfoundland Power’s previous technology and training investments in the Microsoft platform. it was determined the moving CSS to a Windows based platform using SQL Server, could reduce current support costs. As an example, by focusing skill sets in particular areas of expertise which could then be more readily leveraged though out the IT department, Newfoundland

Power would be be able to drive more benefit from available training and support budgets..

In addition, Microsoft was asked to provide examples and support evidence that Windows Server and SQL Server are capable of supporting the type of mixed batch/on-line environment present at NF Power and to provide recommendations as to the best way in which to implement this system using Microsoft technologies such as Windows Server and SQL Server.

Three potential options are outlined within the remainder of this document as solutions for the CSS migration. These include various combinations of UNIX or Windows with either Oracle or SQL Server as the backend database. Each option has benefits and drawbacks which are discussed.

Project Budgeting

Pricing is outside of the scope of this document and quotations for each piece of the CSS application should be discussed with the potential vendors to determine a reasonably accurate price and timeline.

Given the fact that the budget for this project is somewhat fixed, project management principles dictate that an “order of magnitude estimate” be used to determine a “go/no-go” decision for NF Power. This type of estimate is a ballpark figure that states realistically what the lowest reasonable price is for the implementation of the entire system. This estimate is only expected to be accurate +/- 50% of the final total, but is intended to give an “order of magnitude” for a potential customer to determine at a high level, what an approximate budget would be.

Due to the size and nature of the CSS migration, a responsible estimate for the system would be between $3.5 and $4.5 million CAD. This is based on previous migration experience, and the nature of the hardware and software that required for operating the system.

Next Steps for CSS Project Continuance

The following outline some steps that should be taken by Newfoundland Power in order to move the CSS project forward in a responsible and timely manner.

Obtain Accurate Pricing and Schedules from Appropriate Vendors

Currently, all pricing for CSS is approximate and no vendors have been consulted to gain accurate and realistic pricing. Newfoundland Power should engage the vendors listed in the later sections of the document to help determine the overall project costs and delivery schedule.

Solidify Project Budget

Once, pricing and schedules have been determined, a concrete budget needs to be retained in order to assure that the project can move forward.

Complete Business Case and ROI analysis

Presently no business case has been completed for the CSS project. Newfoundland Power needs to determine business drivers for completing the migration project and identify acceptable levels of ROI for the migrated system. Figures for the costs of the CSS project can be attained from the project vendors and internal costs for technical resources can be used to estimate the costs for Newfoundland Power internal resources.

This phase is critical to the success of the CSS project as it will help to identify to senior management, the benefits of migrating the application to a modern platform and will ease the process of solidifying budgets.

CSS Architecture

At present the CSS application is made of two distinct but interdependent parts. These are the on-line systems and the batch systems. The following sections describe both environments and the roles they play within NF Power.

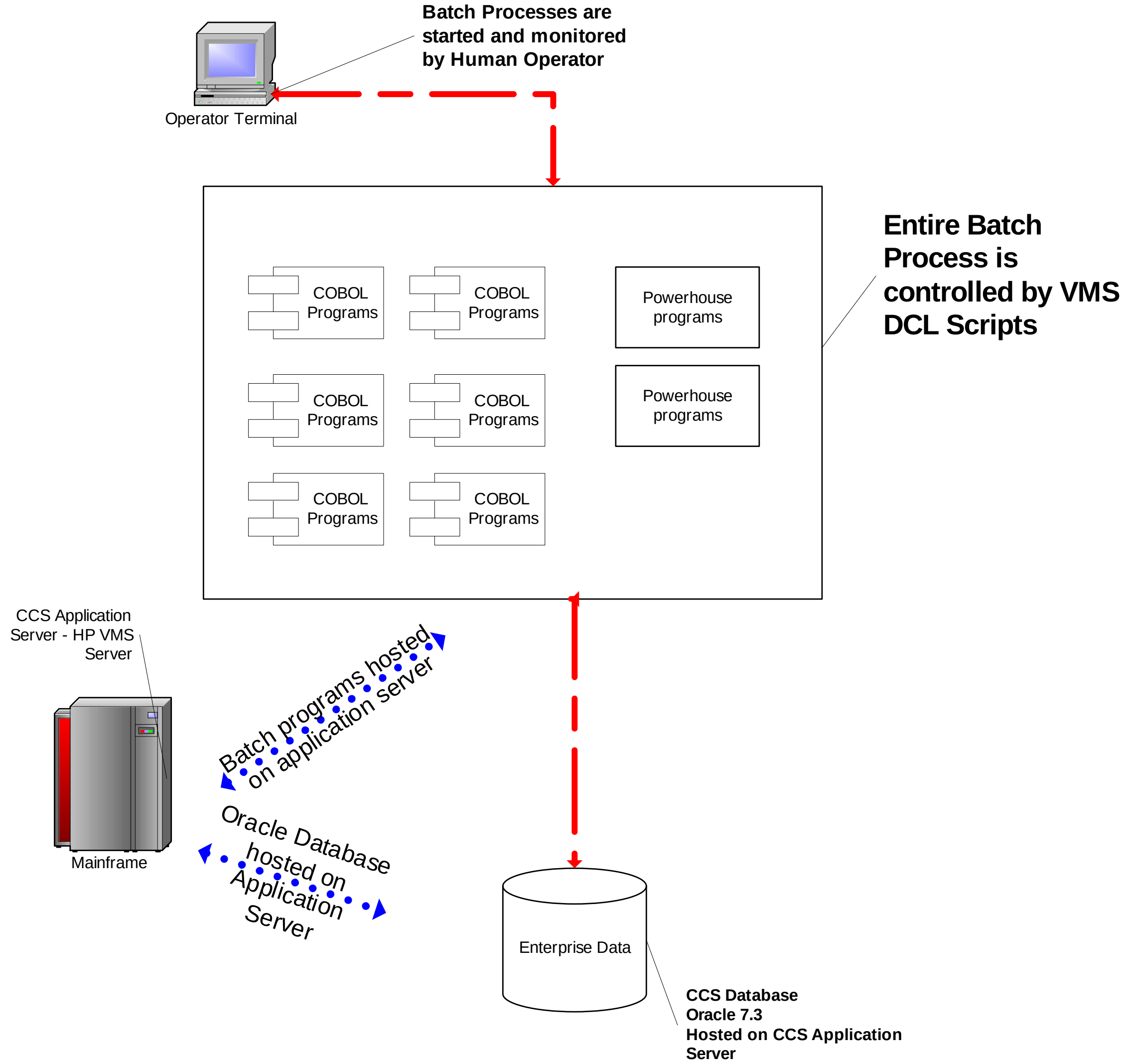
Presently, the on-line and batch systems cannot operate in parallel. The On-Line screens are used by the call center from 8:00 am to 8:00 pm during which time no batch processing is allowed. After the closing of the call center at 8:00 pm, the batch system is then prepared for the night's batch run. During the batch run, invoices are created, payments are reconciled, bank payment files are processed and reports are generated, and then balanced etc. This entire process can take upwards of 10.5 hours to complete and during which time, an operator is required to monitor the entire process manually and check and correct any errors that may occur within the process. This requires that someone be present to monitor the batch jobs during the hours of 8:00 pm to 8:00 am.

Once the batch jobs have been completed, the operator telephones the call center manager to inform them that the system is ready for use, or that the system needs to remain off-line until the batch jobs have completed. In a worse case scenario, the updates from the previous evening may not complete and the entire call center application needs to remain off-line until this finishes. This results in a loss of productivity and customer satisfaction as the call center will not be able to accept customer inquiries until this system is available.

CSS On-Line Environment

The on-line portion of CSS exists to support NF Power's call center operations and customer information system. These provide screens to access customer information, provide billing detail information, and to facilitate services to customers such as service connects and disconnects.

Figure 1: On-line environment



Application Facts:

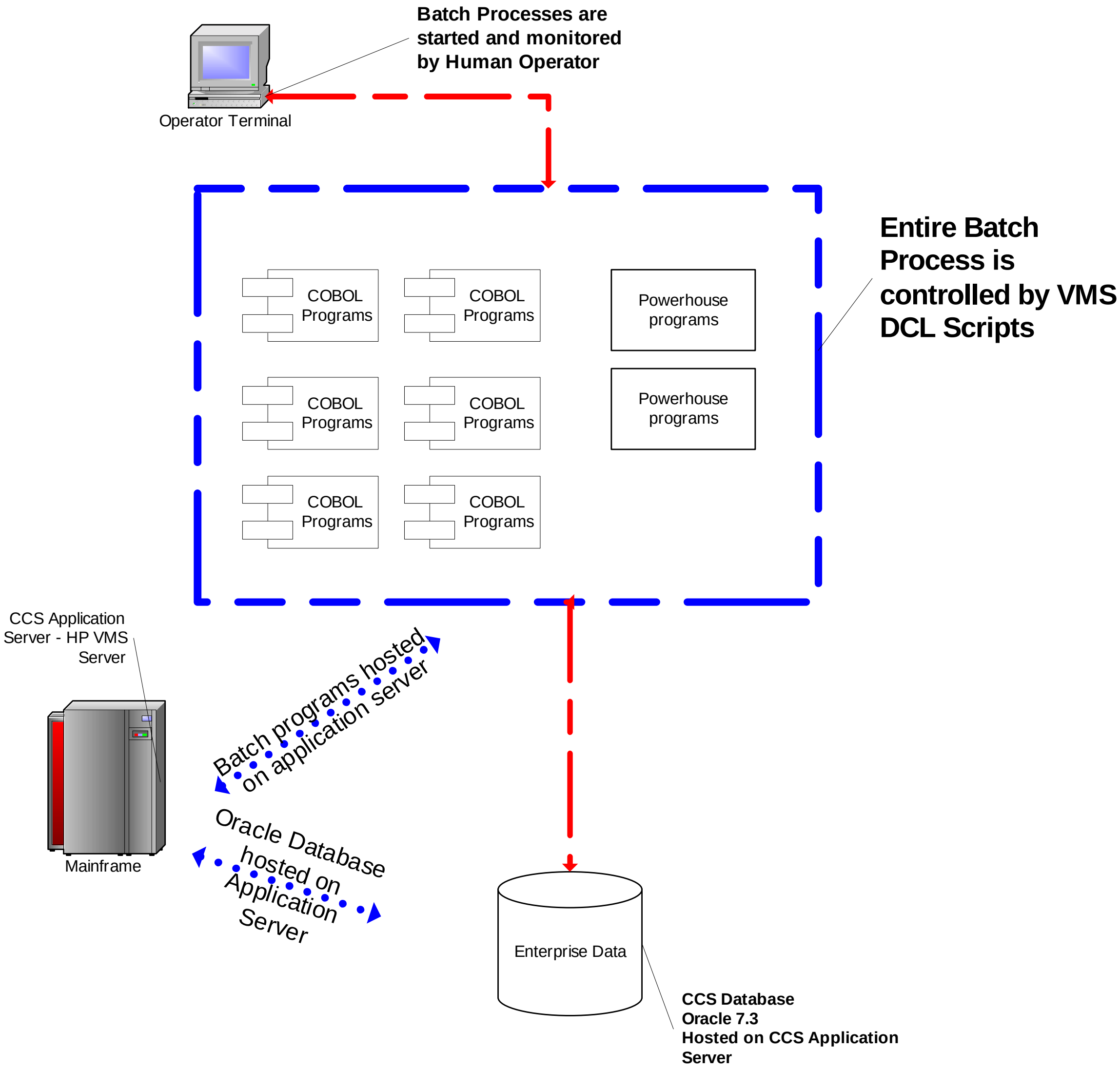
500,000 Lines of COBOL Code
1400 DCL scripts ~60,000 lines
Updates approximately 1GB of data per batch
~10 Oracle Stored Procedures

Batch updates occur during 8:00 PM to 8:00 AM while on-line system is unavailable

CSS Batch Environment

The batch environment for CSS is used balance transactions and payments made throughout the day; issue invoices and perform auditing and accounting functions. This system is entirely text based and requires an operator to be present throughout the entire process.

Figure 2: Batch environment



Application Facts:

500,000 Lines of COBOL Code
1400 DCL scripts ~60,000 lines
Updates approximately 1GB of data per batch
~10 Oracle Stored Procedures

Batch updates occur during 8:00 PM to 8:00 AM while on-line system is unavailable

CSS Migration Project Risks and Assumptions

In order to analyze the options for the migration of the CSS application, it is necessary to state the risks and assumptions that have been identified at the outset of the project. These will help to determine the boundaries and criteria for which each option will be evaluated against. In addition, this will help to give NF Power a starting point for discussions with potential solution vendors.

Project Assumptions

Existence of Migration Vendors and Technologies

It is assumed that vendors will be readily available who can migrate the CSS application without having to rewrite the core business logic functionality. After having preliminary discussions with several vendors, the following short list has been created which outlines potential vendors and solution options:

Powerhouse (On-Line screens and Batch Programs)

Core Software – Core has the technology to migrate the existing Powerhouse code to a Microsoft .Net centric platform running on Windows Server. This can be either in the forms of a Thick Client application (WinForms), or a Web Client (WebForms). After preliminary discussions with Core, it was determined that this would be a viable option and would preserve the business logic coded in Powerhouse, while at the same time moving the applications to a more modern platform.

COBOL (Batch Programs and On-Line External Programs)

Sector 7 – Sector 7 has the technology to migrate the existing COBOL programs from VMS Cobol to other platforms such as Microfocus COBOL running on Windows Server.

Fujitsu – Fujitsu has recently developed COBOL.Net which will allow Newfoundland Power to migrate the existing VMS COBOL programs to COBOL.Net which will run on Windows and can talk natively to the migrated .Net front-end.

Stored Procedures and SQL migration to SQL Server

Core Software / Sector 7 – Both these vendors have the technology to forward engineer Stored Procedures from Oracle to SQL Server. This can be done in addition to migrating the code from VMS to Windows.

Enterprise Job Scheduling and Batch Management

Two potential products can be used by NF Power to facilitate the Job/Batch management features of the current system. NF power has requested that potential Windows/GUI based solutions be identified and evaluated as part of the migration effort. Two potential solutions are given below.

1. Opalis Job Engine – Opalis software
   http://www.opalis.com/products/jobengine/index.html

2. Autosys Job Management – Computer Associates
   http://www3.ca.com/Solutions/Product.asp?ID=253

The evaluation and testing of these tools is not within the scope of this document and should be completed by NF Power technical staff in order to determine the most suitable and cost-effective tool for their enterprise.

Preference not to Re-write application

Given that the entire CSS application is custom coded for NF Power, an application re-write has been deemed not feasible and too risky. This was based on the assumption that re-writing the application will introduce the possibility of new bugs which are not present in the system, and will increase overall project risk vs. simply migrating the application to a new platform.

Estimated Project Budget and Costs

In an ideal world, NF Power would prefer to replace the CSS functionality with an off shelf package such as SAP or Peoplesoft. Estimated cost for an implementation of these products would be fall within $10-$20 million CAD, a migrated solution must cost less than this option. Ideally, the project would be completed for between $4-$6 CAD million inclusive of all costs such as hardware, software and services.

Preference to Maintain a Homogeneous Environment

Currently, Newfoundland Power makes extensive use of Microsoft Technologies such as the Windows Client, Windows Server, and Office Suite. In addition, several pilots are testing additional products such as InfoPath, and Sharepoint Portal Server. It would be preferable to have CSS utilizing these technologies. This has several key benefits such as

1) Re-usability of staff skill sets – It has been identified that it would be desirable to decrease the different skill sets required to support the various applications within Newfoundland Power. In addition to IT staff skill sets, end users acceptance will be higher when applications leverage their exisiting skills and understanding.

2) Increased ability to leverage enterprise support from one vendor – Should the CSS application be developed for the Windows platform using SQL Server, it would be much more cost effective to purchase support from Microsoft and have it serve as support for all applications using Windows within the enterprise. Presently the CSS application uses VMS and Oracle and separate licenses and support are required to support the application which are separate from the enterprise licensing and support agreements from Microsoft.

3) More readily available and cost effective external resource options. When and if Newfoundland Power requires temporary external resources to supplement in house IT Services, the skill set will be more widely available and provide levels for cost comparisons.

Preference to Migrate On-Line component to thick client

After a review of the application with the call center users, if was decided that the application should be migrated to a thick client implementation using Windows Forms technologies. This was decided after agreeing that introducing a Web based application would result in higher re-training time for the call center users, as well as introduce un-wanted latency between client requests and server responses. This introduces a key assumption that the newly migrated system must provide the same level of responsiveness as the current system in order to assure client satisfaction. At present, the On-Line component of the CSS system is very responsive and performance is not an issue for end users.

Project Risks

Highly visible and reliable nature of current system

Given that the CSS system is critical to the revenue generation and day to day operations within NF Power, attempting a migration of this system inheritably brings with it, an increased level of risk. This is multiplied by the fact that the current system is quite stable and meets all performance and up-time requirements for NF Power. In addition, the On-Line portion of CSS has a >90% customer satisfaction rate. Any changes to the system will need to be thoroughly investigated and tested before implementation to ensure that these benchmarks are met by the new system.

Incremental Cost of Migrating Database to SQL Server 2000

Currently, the CSS system uses Oracle as its backend data store. Given that NF Power has expressed an interest in having the new system use SQL Server as its database brings with it an increased amount of risk as it is another change that will have to be implemented and supported within the new application. However, this risk needs to be weighed against the licensing and support costs the Oracle requires specifically for the CSS application along with additional support resources that are specifically dedicated to supporting Oracle. Given that NF Power has already deployed SQL Server on many of their internal applications, there should be cost savings associated with migrating CSS to use SQL Server as well. These cost savings will need to be compared against the incremental costs of converting CSS to use SQL Server instead of Oracle during the migration phase of the project.

Perceived Scalability of Windows Platform by NF Power

During initial discussions with NF Power technical staff, there was a perceived notion that the Windows Platform would not be able to perform as well as other CSS platform options. Several concerns were raised including

1) Performance of Windows in a highly batch orientated environment

2) Scalability/Reliability of Windows & SQL Server within the CSS environment.

3) Security of Windows Server when compared to Unix/VMS

These issues can be addressed by Microsoft sales/technical resources upon further investigation with NF Power personnel. Specifically, case studies and customer references can be provided to prove the stability and reliability of the Windows platform in relation to Unix/VMS to a level where NF Power is comfortable with Windows and SQL Server as the primary technologies for CSS.

Potential CSS Architecture Options

Option 1 (RECOMMENED) – Migration of CSS to Windows using SQL Server

This option would entail migrating the Axiant PowerHouse application to a .Net Application using Windows Forms. The database would also be replaced with SQL Server using an Active/Passive cluster. An application Server can be used to shared application logic and common programs across all clients. This would allow NF Power to shared database access and common COBOL programs to all CSS Workstations without deploying them to each computer. The application servers can also be used to run batch processing at the end of each business day.

The COBOL external programs and Batch programs would be migrated to a Windows Environment running on the shared application servers. At the end of the business day, the application servers would be used to execute batch processing logic and access data on the SQL Server database cluster.

A reporting database would be maintained via SQL Server replication and would be updated once the batch updates have been completed at the end of the batch processing run.

Figure 3 – Option 1 On-Line environment

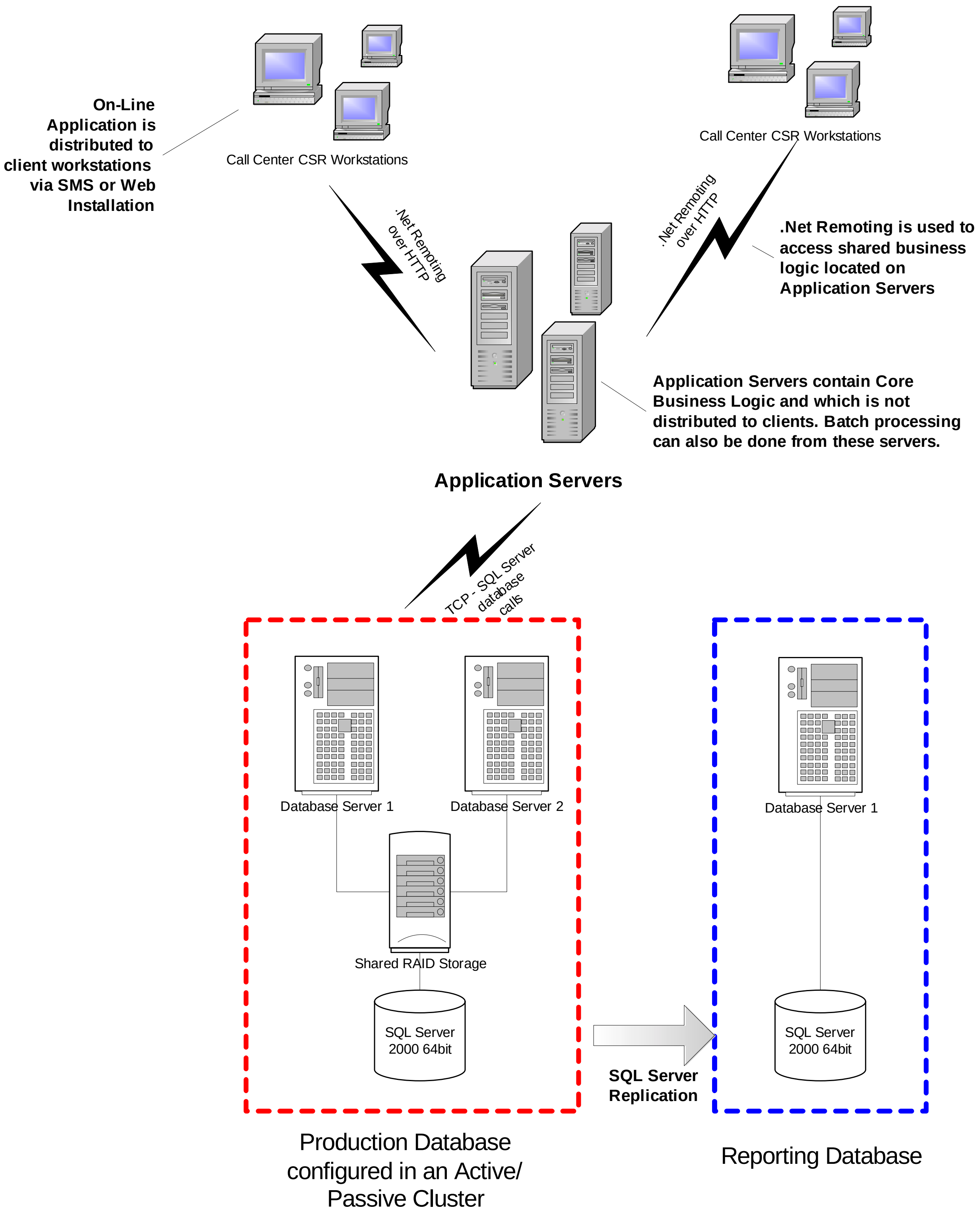
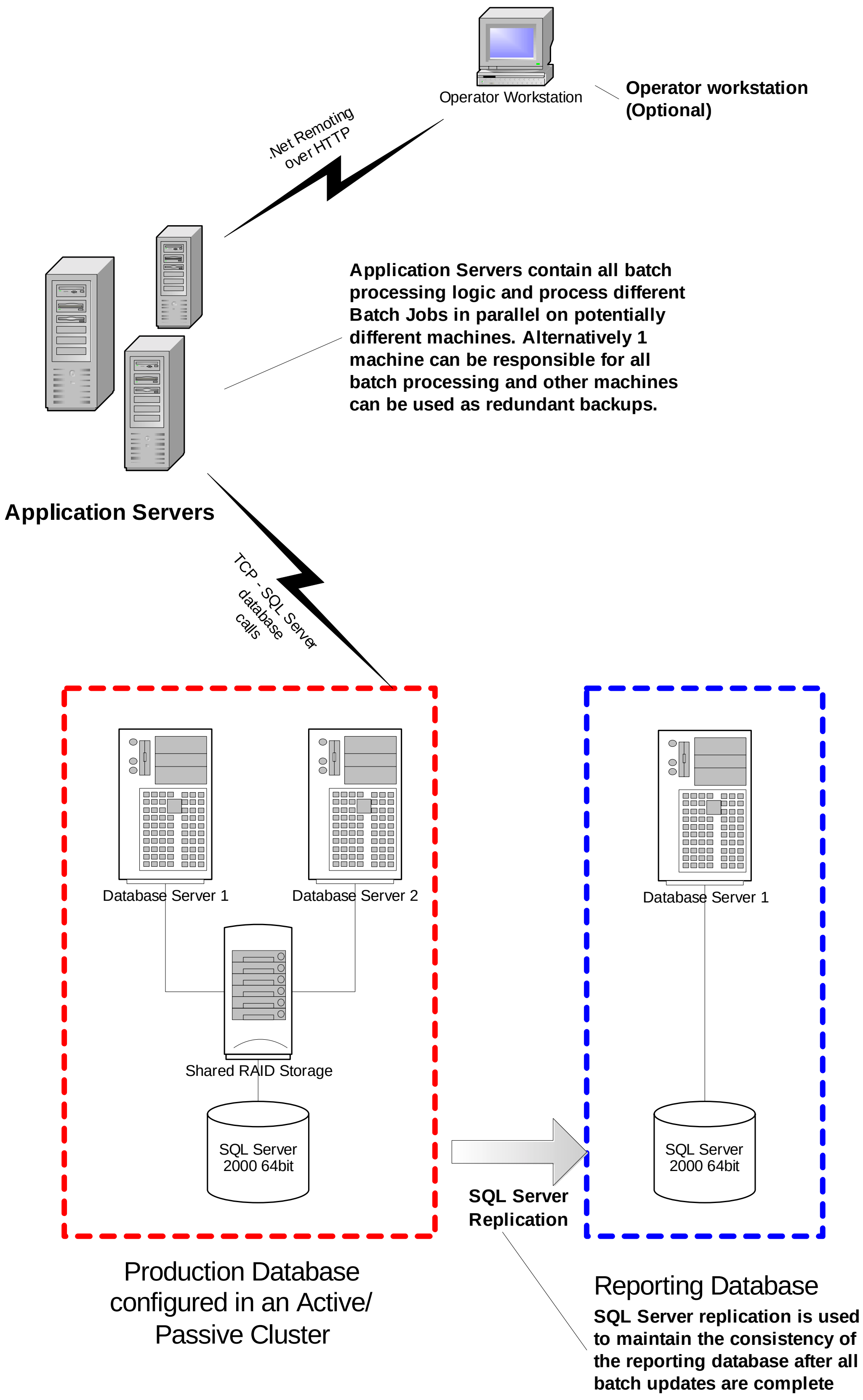


Figure 4 – Option 1 Batch environment



Operator workstation (Optional)

Application Servers contain all batch processing logic and process different Batch Jobs in parallel on potentially different machines. Alternatively 1 machine can be responsible for all batch processing and other machines can be used as redundant backups.

Application Servers

SQL Server Replication

Production Database configured in an Active/ Passive Cluster

Reporting Database

SQL Server replication is used to maintain the consistency of the reporting database after all batch updates are complete

Environment Components and Descriptions

Client Workstations – These are the current workstations for people who are accessing the CSS application. They would have the Thick client application installed from either an SMS install package or from an installation executable. All forms would be hosted on the client as well as some business logic. Communication with the application servers is done via .Net remoting over HTTP. This allows each client workstation to access shared .Net objects which are hosted on a separate machine. The communication protocol would be standard HTTP. Direct Database communication would be done through the standard SQL Server communication libraries over TCP.

Required Software:

1. CSS Thick client application
2. .Net framework redistributable
3. SQL Server client for database connectivity

Application Servers – The application servers are used to distribute business logic throughout the CSS application in a shared and common manner. The application servers would host common COBOL routines and application logic such as database access methods and security settings. These would be Compaq Proliant Servers using Windows Server. These servers can be configured in a Windows Network Load Balancing service to distribute client requests across all machines in the NLB domain. This will help to reduce response times during extremely high usage.

In addition to supporting the On-Line environment, the application servers would be used to process the batch updates and routines at the end of the business day. This can be accomplished in a variety of ways. Each server can be configured to run only certain batch processes and jobs which can run in parallel can be executed on different machines. Jobs that require pre and post processing logic can be run on 1 machine.

This will allow the batch jobs to get maximum CPU usage across the application server farm and at the same time, maximize access to the database cluster. Microsoft Operation Manager and Application Center 2000 can be used to monitor the health of each server and ensure that each machine is properly utilized.

Approximate Number of Servers: (2 – 3 Depending on amount of batch processing to be executed on each machine)

Required Software:

1. COBOL External On-Line Programs
2. Windows Network Load Balancing
3. Windows Server Standard
4. .Net Framework redistributable
5. SQL Server client for database connectivity
6. Batch Scheduling and Monitoring tool
   a. http://www3.ca.com/Solutions/Product.asp?ID=253
   Autosys from CA
   b. http://www.opalis.com/products/jobengine/index.html
   Opalis Job Engine
7. COBOL Batch processing code

Optional Software:

1. Microsoft Operation Manager
2. Microsoft Application Center 2000

Production Database Servers – This component would entail a SQL Server 2000 64bit cluster of database servers in an Active/Passive configuration. This would allow NF Power to maintain a “Hot Standby” database server in the event one database server was to become unavailable. In this case, the hot standby would take ownership of the cluster and then begin to respond to database requests while the other server in the cluster was offline.

Shared storage is accomplished through the use of a shared raid array storage device which is connected via fiber channel to each node in the cluster. All database datafiles and transaction logs would be stored on this shared array allowing both nodes in the cluster to access it.

Again, MOM and Application Center can be used to monitor the health and status of each node in the SQL Server cluster as well to notify support technicians of any hardware failure or cluster failover.

Approximate Number of Servers: (2 Cluster Node Servers with 1 shared Raid array storage device)

Required Software:

1. Windows Advanced Server 64Bit
2. Windows Clustering Server
3. Microsoft SQL Server 2000 Enterprise 64 bit

Optional Software:

1. Microsoft Operation Manager
2. Microsoft Application Center 2000

Reporting Database Servers – The reporting database would contain an up-date copy of the previous evening's batch updates available for ad-hoc queries and OLAP cube analysis. At the end of an evenings batch updates, SQL Server replication would be used to transfer a read-only copy of the production database to a smaller, non-clustered SQL Server which would be available to users on an ad-hoc basis to run non-standard queries and reports.

In addition to ad-hoc queries, the reporting database could be used to run the standard batch reporting that currently executes on the production database server. This would allow NF Power to separate the batch updating and batch reporting into two separate processes thus allowing a greater window for batch updating to occur as well as decreasing the amount of time an operator needs to be present during the batch updating process. The standard batch reports can be executed automatically against the reporting database once the SQL Server replication from production is completed.

Approximate Number of Servers: (1 Non-Clustered SQL Server)

Required Software:

1. Windows Server
2. Microsoft SQL Server 2000 Standard

Optional Software:

1. Microsoft Operation Manager
2. Microsoft Application Center 2000

Option 1 Benefits

Decreased Oracle licensing / support costs

Option 1 allows NS Power to decrease the Oracle licensing and support costs and utilize a standard Enterprise Support Agreement for all Microsoft technologies. This will give NF Power the ability to leverage Microsoft PSS support for both Desktop and Server support. This will also remove the need to purchase annual Oracle support

Reuse of existing SQL Server Skill sets

NF Power already has SQL Server skill sets internally and these can be re-used for the CSS project rather than maintaining a separate Oracle/VMS skill set for CSS

Less Expensive Hardware than Unix solution

Hardware costs for option 1 will be less expensive than a similarly architected Unix solution.

Ability to Integrate other technologies such as Sharepoint and Infopath

As NF Power is presently investigating other Microsoft technologies which can access SQL Server as a native datasource, integrating these technologies into CSS will be much easier with a SQL/Windows solution. In addition, should NF Power use BizTalk Server as a mechanism to transfer text and XML files or to facilitate Business Process Automation, licenses will already be purchased for the SQL Server component of BizTalk and will not need to re-purchased.

Option 1 Major Drawbacks

Need to convert Oracle portion of CSS during application migration

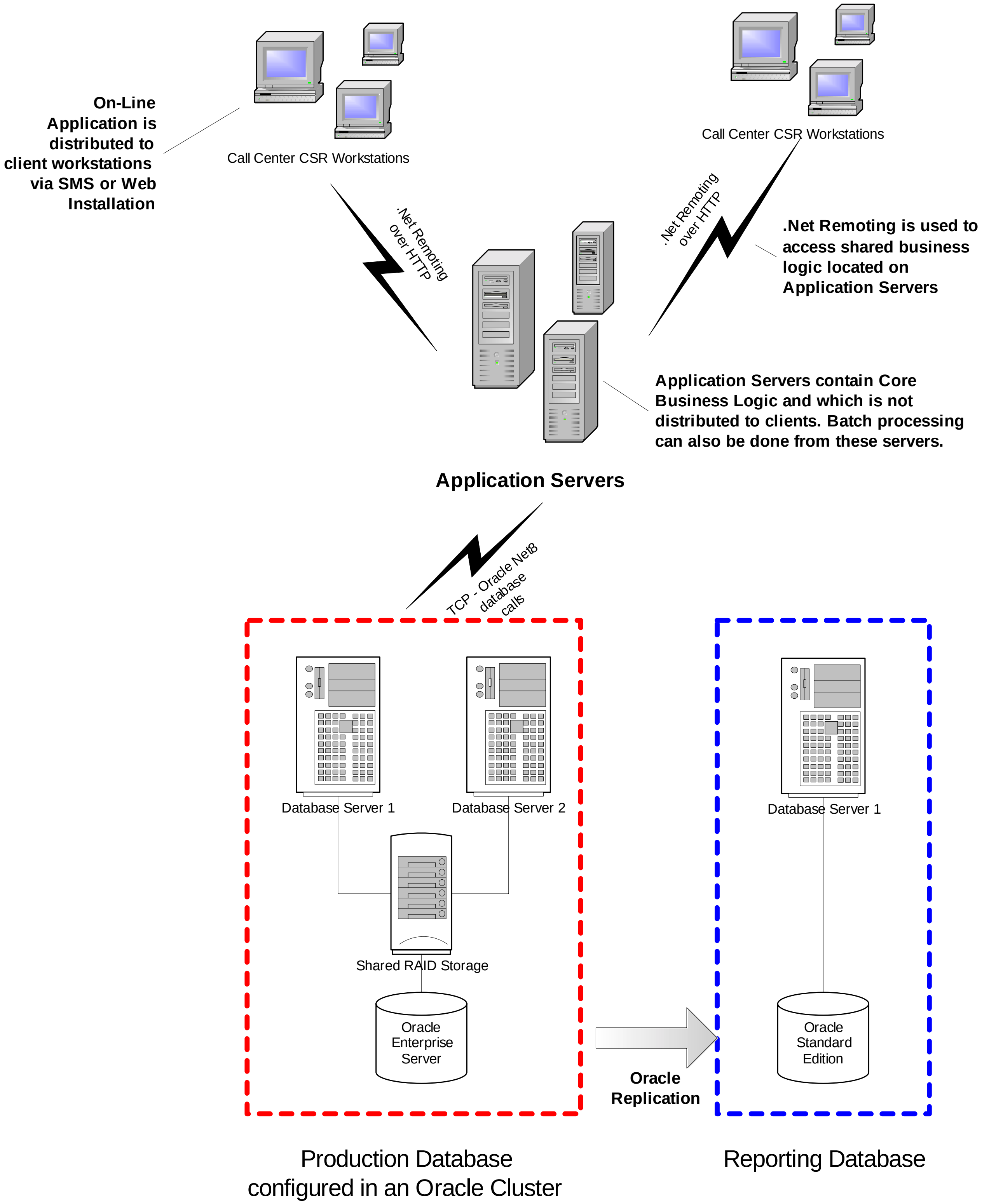
As the current application is written using Oracle, all in-line SQL Statements and Stored Procedures will need to be converted to use SQL Server syntax. This will also increase project risk as it adds another level of complexity to the migration effort.

Option 2 – Migration of CSS to Windows using Oracle

This option is nearly identical to option 1 with the exception that the migration to SQL Server would not be attempted and Oracle would be used as the backend database platform. Similar clustering and failover for the production system can be implemented using Oracle's RAC technology and Windows Clustering. Oracle replication can also be used to synchronize the reporting database with the production database after each night's batch processing completes.

It is important to note that because Oracle does not currently have a 64bit implementation for the Windows platform, all database servers will need to be Windows Server 32 bit versions. The application servers should also be 32 bit windows as in option 1 as the majority of the application processing is completed in the database servers and increasing processing power on the application servers most likely would not yield any benefit.

Figure 5 – Option 2 On-Line environment

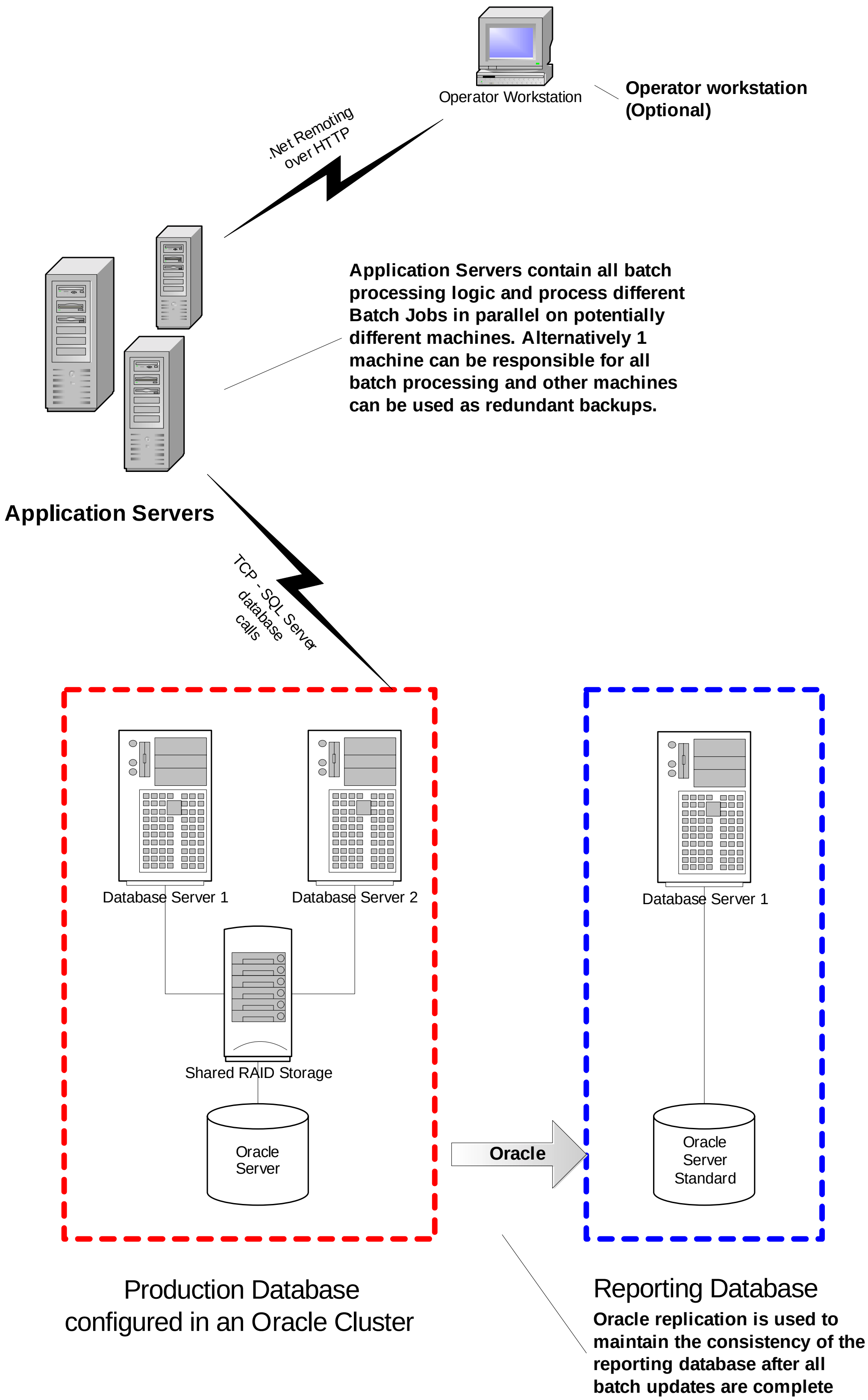


On-Line Application is distributed to client workstations via SMS or Web Installation

.Net Remoting is used to access shared business logic located on Application Servers

Application Servers contain Core Business Logic and which is not distributed to clients. Batch processing can also be done from these servers.

Figure 6 – Option 2 Batch environment



Operator workstation (Optional)

Application Servers contain all batch processing logic and process different Batch Jobs in parallel on potentially different machines. Alternatively 1 machine can be responsible for all batch processing and other machines can be used as redundant backups.

Application Servers

Production Database configured in an Oracle Cluster

Reporting Database

Oracle replication is used to maintain the consistency of the reporting database after all batch updates are complete

Environment Components and Descriptions

Client Workstations – These are the current workstations for people who are accessing the CSS application. They would have the Thick client application installed from either an SMS install package or from an installation executable. All forms would be hosted on the client as well as some business logic. Communication with the application servers is done via .Net remoting over HTTP. This allows each client workstation to access shared .Net objects which are hosted on a separate machine. The communication protocol would be standard HTTP. Direct Database communication would be done through the standard Oracle communication libraries over TCP.

Required Software:

1. CSS Thick client application
2. .Net framework redistributable
3. Oracle client for database connectivity

Application Servers – The application servers are used to distribute business logic throughout the CSS application in a shared and common manner. The application servers would host common COBOL routines and application logic such as database access methods and security settings. These would be Compaq Proliant Servers using Windows Server. These servers can be configured in a Windows Network Load Balancing service to distribute client requests across all machines in the NLB domain. This will help to reduce response times during extremely high usage.

In addition to supporting the On-Line environment, the application servers would be used to process the batch updates and routines at the end of the business day. This can be accomplished in a variety of ways. Each server can be configured to run only certain batch processes and jobs which can run in parallel can be executed on different machines. Jobs that require pre and post processing logic can be run on 1 machine.

This will allow the batch jobs to get maximum CPU usage across the application server farm and at the same time, maximize access to the database cluster. Microsoft Operation Manager and Application Center 2000 can be used to monitor the health of each server and ensure that each machine is properly utilized.

Approximate Number of Servers: (2 – 3 Depending on amount of batch processing to be executed on each machine)

Required Software:

1. COBOL External On-Line Programs
2. Windows Network Load Balancing
3. Windows Server Standard
4. .Net Framework redistributable
5. Oracle client for database connectivity
6. Batch Scheduling and Monitoring tool
   a. http://www3.ca.com/Solutions/Product.asp?ID=253
      Autosys from CA
   b. http://www.opalis.com/products/jobengine/index.html
      Opalis Job Engine
7. COBOL Batch processing code

Optional Software:

1. Microsoft Operation Manager
2. Microsoft Application Center 2000

Production Database Servers – This component would entail an Oracle database cluster which would be available to respond to incoming database requests. This would allow NF Power to maintain a redundant database server in the event one database server was to become unavailable.

Shared storage is accomplished through the use of a shared raid array storage device which is connected via fiber channel to each node in the cluster. All database datafiles and transaction logs would be stored on this shared array allowing both nodes in the cluster to access it.

MOM could be used to monitor the health of the servers in the database and Oracle Enterprise Manager would be used to monitor and administrate the database.

Approximate Number of Servers: (2 Cluster Node Servers with 1 shared Raid array storage device)

Required Software:

1. Windows Advanced Server
2. Oracle Enterprise Server

Optional Software:

1. Microsoft Operation Manager

Reporting Database Servers – The reporting database would contain an up-date copy of the previous evening's batch updates available for ad-hoc queries. At the end of an evenings batch updates, Oracle replication would be used to transfer a read-only copy of the production database to a smaller, non-clustered Oracle Server which would be available to users on an ad-hoc basis to run non-standard queries and reports.

In addition to ad-hoc queries, the reporting database could be used to run the standard batch reporting that currently executes on the production database server. This would allow NF Power to separate the batch updating and batch reporting into two separate processes thus allowing a greater window for batch updating to occur as well as decreasing the amount of time an operator needs to be present during the batch updating process. The standard batch reports can be executed automatically against the reporting database once the Oracle replication from production is completed.

Approximate Number of Servers: (1 Non-Clustered Oracle Server)

Required Software:

1. Windows Server
2. Oracle Database Server

Optional Software:

1. Microsoft Operation Manager

Option 2 Benefits

Reuse of existing CSS Oracle Skill sets

As CSS currently is implemented using Oracle, this solution will allow NF Power to re-use the same support skills that are currently in place. In addition, existing database tools can be re-used across between the old system and the new system.

Less Expensive Hardware than Unix solution

Hardware costs for option 1 will be less expensive than a similarly architected Unix solution.

Simpler Database Migration Effort

As CSS is currently implemented using Oracle on OpenVMS, migrating the system to Windows using Oracle will present less problems than if CSS were to use SQL Server as the database platform.

Option 2 Major Drawbacks

Continued need to purchase separate Oracle support for CSS

CSS will still require that additional Oracle support be purchased in order to support the CSS environment. This will be over and above any enterprise support that is purchased from Microsoft.

Additional products required for OLAP and Cube analysis functionality within the reporting server

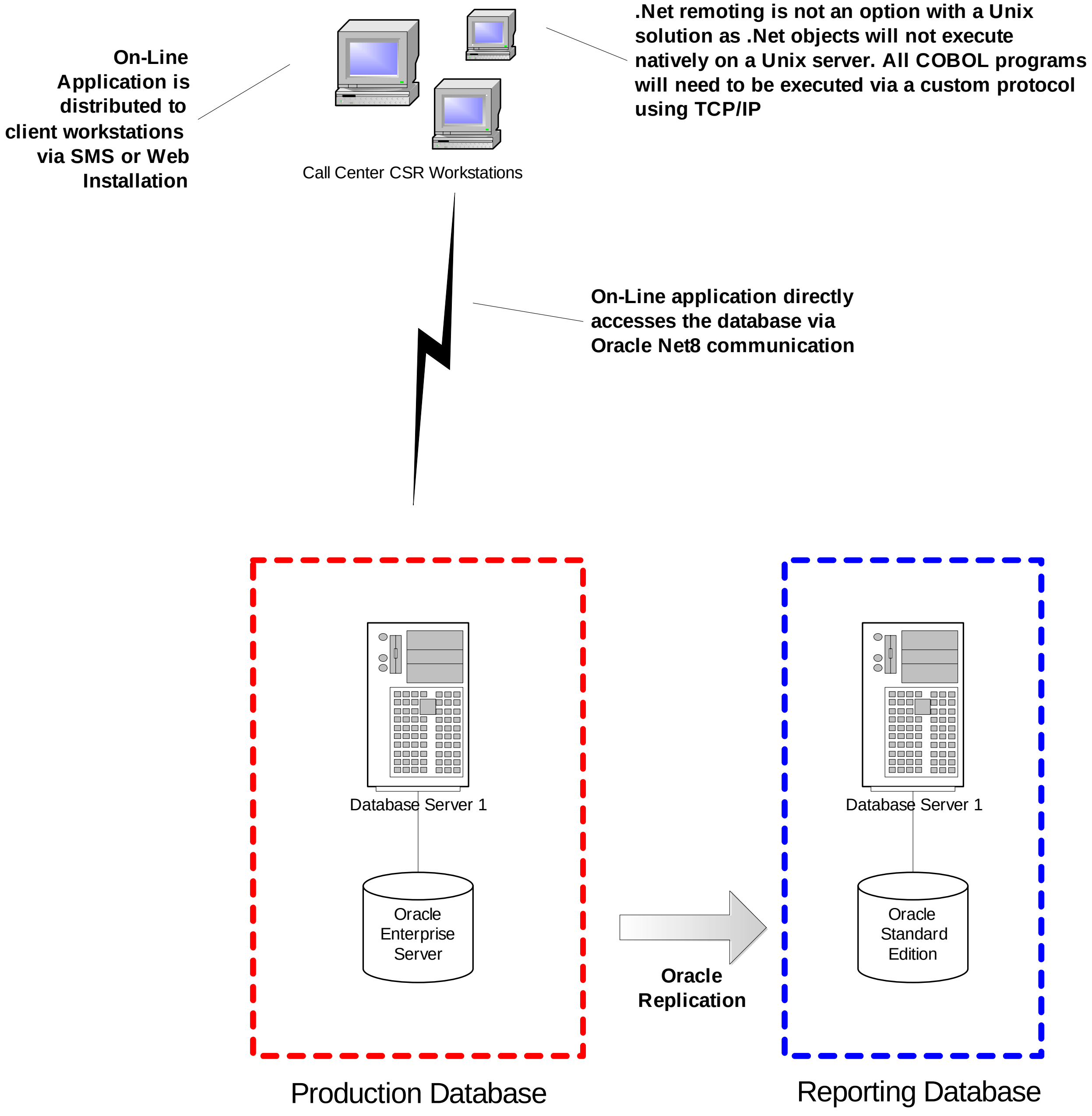
Since, SQL Server will not be available for OLAP and cube analysis, Oracle Analysis server or Cognos Server will need to be purchased should NF Power wish to use this functionality within CSS. This functionality is included within SQL Server and is part of the install.

Option 3 – Migration of CSS to Unix using Oracle

This option is nearly identical to option 1 with the exception that the migration to SQL Server would not be attempted and Oracle would be used as the backend database platform. Similar clustering and failover for the production system can be implemented using Oracle's RAC technology and Windows Clustering. Oracle replication can also be used to synchronize the reporting database with the production database after each night's batch processing completes.

It is important to note that because Oracle does not currently have a 64bit implementation for the Windows platform, all database servers will need to be Windows Server 32 bit versions. The application servers should also be 32 bit windows as in option 1 as the majority of the application processing is completed in the database servers and increasing processing power on the application servers most likely would not yield any benefit.

Figure 7 – Option 3 On-Line environment



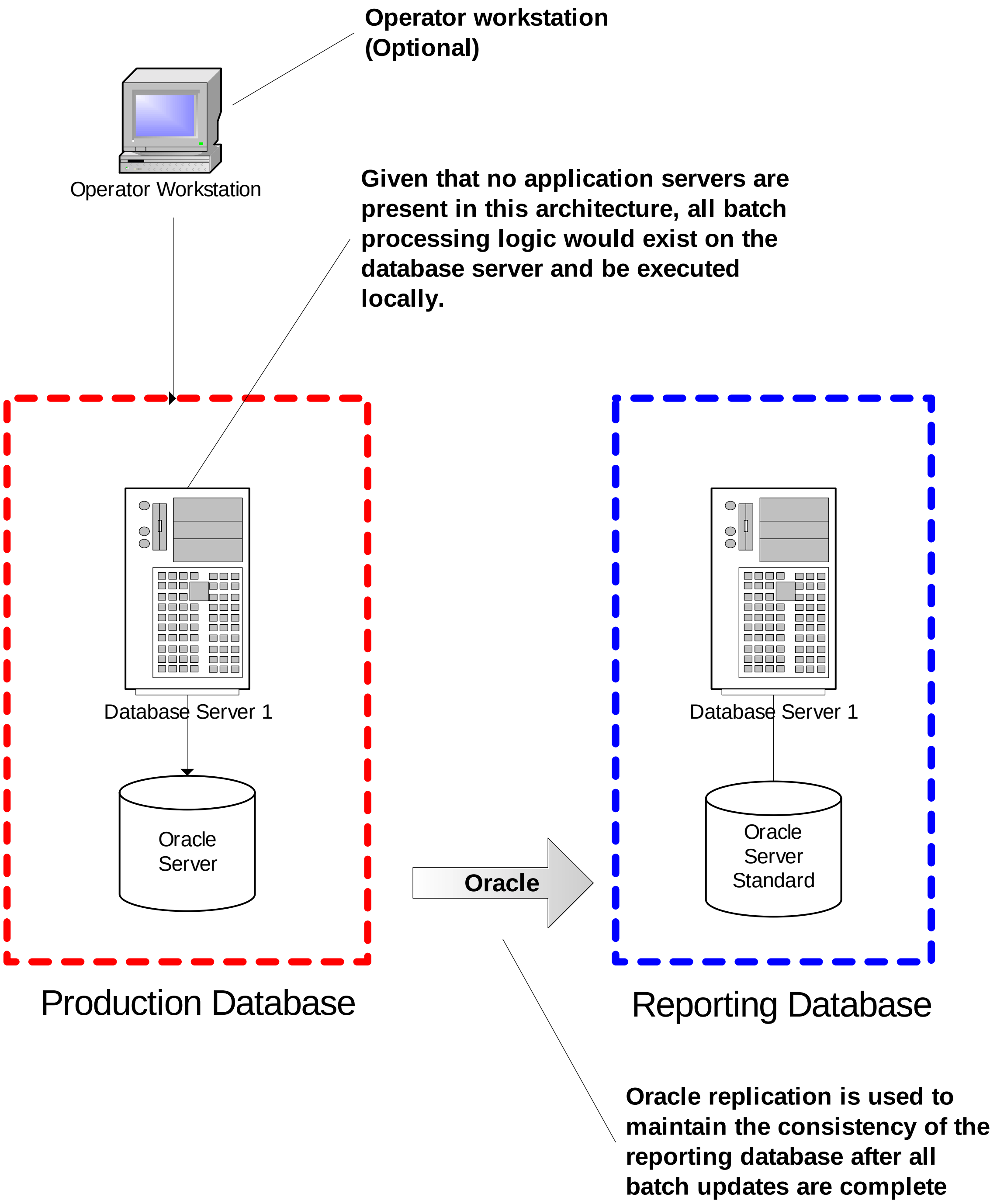
On-Line Application is distributed to client workstations via SMS or Web Installation

.Net remoting is not an option with a Unix solution as .Net objects will not execute natively on a Unix server. All COBOL programs will need to be executed via a custom protocol using TCP/IP

On-Line application directly accesses the database via Oracle Net8 communication

Oracle Replication

Figure 8 – Option 3 Batch environment



Operator workstation (Optional)

Given that no application servers are present in this architecture, all batch processing logic would exist on the database server and be executed locally.

Oracle replication is used to maintain the consistency of the reporting database after all batch updates are complete

Environment Components and Descriptions

Client Workstations – These are the current workstations for people who are accessing the CSS application. They would have the Thick client application installed from either an SMS install package or from an installation executable. All forms would be hosted on the client as well as some business logic. Communication with the application servers is done a custom protocol using TCP. This allows each client workstation to access shared COBOL code which is hosted on a separate machine. Direct Database communication would be done through the standard Oracle communication libraries over TCP.

Required Software:

1. CSS Thick client application
2. .Net framework redistributable
3. Oracle client for database connectivity

Application Servers – After discussions with NF Power personnel, it was decided, that this option would not include an application server. This was decided for a number of reasons. The most of important of these reasons was the incremental cost of additional UNIX servers to the architecture would increase the cost of the project to a point where the benefit of the additional processing power was not justified.

Given that no application servers would be present in this architecture, all batch processing would be performed on the database server and be run as local programs and jobs.

Production Database Servers – Essentially the production database server would host the entire CSS application. The database server would serve as both the application server and the database server for all batch components.

Approximate Number of Servers: (1 UNIX server)

Required Software:

1. Unix
2. Oracle Enterprise Server
3. All batch processing code
4. All batch COBOL code
5. Enterprise Batch scheduling and Management tools

Reporting Database Servers – The reporting database would contain an up-date copy of the previous evening's batch updates available for ad-hoc queries. At the end of an evenings batch updates, Oracle replication would be used to transfer a read-only copy of the production database to a smaller, non-clustered Oracle Server which would be available to users on an ad-hoc basis to run non-standard queries and reports.

In addition to ad-hoc queries, the reporting database could be used to run the standard batch reporting that currently executes on the production database server. This would allow NF Power to separate the batch updating and batch reporting into two separate processes thus allowing a greater window for batch updating to occur as well as decreasing the amount of time an operator needs to be present during the batch updating process. The standard batch reports can be executed automatically against the reporting database once the Oracle replication from production is completed.

Approximate Number of Servers: (1 UNIX Oracle Server)

Required Software:

1. UNIX
2. Oracle Database Server

Option 3 Benefits

Reuse of existing CSS Oracle Skill sets

As CSS currently is implemented using Oracle, this solution will allow NF Power to re-use the same support skills that are currently in place. In addition, existing database tools can be re-used across between the old system and the new system.

Simpler Database Migration Effort

As CSS is currently implemented using Oracle on OpenVMS, migrating the system to Windows using Oracle will present less problems than if CSS were to use SQL Server as the database platform.

Option 3 Major Drawbacks

Continued need to purchase separate Oracle support for CSS

CSS will still require that additional Oracle support be purchased in order to support the CSS environment. This will be over and above any enterprise support that is purchased from Microsoft.

Additional products required for OLAP and Cube analysis functionality within the reporting server

Since, SQL Server will not be available for OLAP and cube analysis, Oracle Analysis server or Cognos Server will need to be purchased should NF Power wish to use this functionality within CSS. This functionality is included within SQL Server and is part of the install.

Lack of UNIX Skill sets within NF Power

At present, NF Power does not have the skill sets internally to support a large scale UNIX implementation. These skill sets would have to be purchased externally or existing staff would need additional training and ramp-up time to attain the same level of comfort and skill that is present with the OpenVMS platform and Windows.

Cost of Hardware and lack of skill sets make clustering less attractive

Since each UNIX server is quite expensive, scaling and clustering becomes less of an attractive option with the UNIX solution. The outlined architecture has no-redundancy or scaling-out potential defined and should this be required, additional servers would need to be priced and purchased.

Appendix Q - HP Technical Migration Assessment Report External

HP Technical Migration Pricing

-----Original Message-----
From: Spriggs, Arthur [mailto:Arthur.Spriggs@hp.com]
Sent: Monday, May 12, 2003 8:49 AM
To: dbatston@newfoundlandpower.com
Subject: RE: Newfoundland Power Assessment

I have done a review of the pricing with the boys in the states.

What we don't want is a situation (that is common in the conversion industry) that you would received a quotation and the end result is much higher than quoted due to a number of "change requests", as the project went on. We also wanted to reflect an "industry standard" conversion that would not require any proprietary porting tools that would result in costs associated with licensing the conversion result for the lifecycle of the app.

With this being said we have estimated on the high side to allow you to do a more accurate cost of ownership and a more realistic budget preparation.

Based on the number of days involved the costs should come in at $CDN 800K without the conversion of the Cognos side, and $CDN2.5 million if all was converted.

At your request I will set up a con call for a pricing review and overview review for your team.

Newfoundland Power

Application Migration Assessment Report

Preface

Distribution Control

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2. Approval Copy	Newfoundland Power

People Involved in the Preparation of This Document

Function	Name
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IQ Center Systems Engineering Mgr	Bill Lahtinen
Solution Architect	Kerry Main
Systems Engineering Team	Michael O'Neil Petter Erik Carlson

Review List

Reviewed by	Date

Change History

Version	Date	Revision Description
1.0	25 April 2003	Initial Report
1.1	29 April 2003	Review comments included
1.2	1 May 2003	Spelling and format edits

Proprietary Statement

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Acknowledgements

HP would like to express its sincere appreciation to all Newfoundland Power staff that helped with this review by providing their time, information and technical support.

Trademark Notice

This version of the document supersedes all previous versions.

TABLE OF CONTENTS

1. Executive Summary

Hewlett-Packard Corp., an HP Company (hereinafter "HP") was requested to review Newfoundland Power's CSS application environment and provide a quick assessment and recommendations on migrating different parts of the CSS application off of the OpenVMS system to either Microsoft or HP-UX operating systems..

Estimate to reengineer Axiant Powerhouse source files and eliminate the dependence on PowerHouse and migrate DCL batch, Cobol, and all other related applications is 1000 engineer-days of effort on either Unix or Windows platforms.

Estimate to migrate all applications and continued use of Axiant/Powerhouse is 300 engineer-days of effort on either Unix or Windows platforms.

See Section 9 "Sizing" for assumptions details on these estimates

Recommendations

1. The Estimates are based on a strict migration of existing application functionality to a different platform, which would not take full advantage of the next operating system's strong points. HP recommends that an architectural review of the current and target environments be performed to exploit the architecture of the future environment.

2. If the Axiant application development tools are to be replaced (e.g. migrated to MS asp's or Java) this would constitute a substantial amount of change to the existing CSS application and user environment. Refer to Section 5. In this scenario, HP's recommendation is for a phased migration approach and a detailed migration assessment or architectural review of the CSS environment as a prudent next step to mitigate risk.

3. For performance, security, and minimizing migration efforts, HP recommends to wait on making a comprehensive migration to Microsoft until
- Microsoft supports 64 bit hardware (no point in migrating from 64 to 32 hardware and then back again in the future)
- The .NET product becomes a bit more mature (continue to train and work with .NET development, but minimize the risks to the production system)
- Security improves a bit more

4. Recommend a wait on making a comprehensive migration to HP-UX until 2005 when HP-UX 11.i version 3 will include the AdvFS Advanced file system, Tru cluster support and available on Alpha and Itanium processors.

4. Based on your current rate of software builds and updates to your system, HP would not recommend using hardware or software emulators to migrate parts or the entire system to another platform. Refer to Section 3.

2. The Migration Process

Successful migrations and reengineering programs require careful planning and project management to mitigate and reduce risks. An application migration is more than recompilations or modification of existing code onto another hardware platform. One must also consider the impact of test verification and the application environment build process, which are key components of any migration.

3. Hardware and software Emulators

While there are software and hardware emulators that can be used to mimic an existing operating system environment or language, they are not magic bullets. They are fast to implement, they require proprietary software to remain resident on the new platform to support the original software. Obviously, this does not reduce the dependency on multiple vendors.

Emulators and translators tend to leave support engineers in quasi-state of development, debug, and deployment over two operating systems. Until a complete migration or reengineering off of the original platform is completed, the total cost of ownership includes both platforms, emulator licensing, and service contracts.

While emulation is usually good for quick, short term, migrations or work-a-round; they are not recommended for long term application support, especially if the environment is updated and rebuilt on a regular basis.

4. Why migrate or reengineer the application environment?

Migration should be considered for performance reasons

- improved data processing throughput (moving from 32 to 64 bit processing)
- increased capacity and improved response times

Migration should be considered in keeping pace with the evolving business environment when moving to

- more integrated software packages and tools that consolidate business practices and require less internal I.T. support
- open standards and reducing dependencies on single source vendors
- languages and tools that are known to a wider segment of the job market

Reengineering should be considered when the application environment

- does not match the future business model
- there are too many manual work-around with application and the existing business process

- the end user’s support and expectations cannot be met with the environments existing technology

5. Migrating off of Axiant tooling

If the Axiant application development tools are to be replaced (e.g. migrated to MS asp’s or Java) this would constitute a substantial amount of change to the CSS application and user environment. A migration implementation of this extent is known as a ‘Big Bang’ approach. The scope of change and potential impact requires a plan and methodology for a very comprehensive acceptance testing.

In this scenario, recommendation for a detailed migration assessment and a phased migration approach would be a prudent next step. If the Axiant applications are to be reengineered, then an architectural review of the CSS environment would also be prudent.

5.1 Why an architectural review?

Moving from a forms oriented application to an event driven interface, whether the interface is on the web or a conventional GUI interface, presents an opportunity to improve on the User interaction with Customer support, information retrieval. In some cases an event driven application can actually streamline the business process and automate and integrate other parts of the process.

6. Migrating application environment to Microsoft

Many application environments have been migrated to Microsoft and there are good and bad points to this approach. The following sections outline the tradeoffs and advantages of migrating OpenVMS applications to Microsoft

6.1 Tradeoffs and Advantages of Microsoft Environment

6.1.1 Security

The Microsoft environment requires more operational diligence and careful design to achieve the same level of security as Unix or OpenVMS systems.Because Microsoft is the most popular operating system, it is a favored target by Hackers and virus software . The most recent example was the SQL slammer virus which disrupted financial, manufacturing, and government computing systems. Refer to Appendix C

Recent statistics on documented on virus attacks to the different O/S

- tens of thousands of new viruses on Microsoft
- about five thousand on Unix based systems
- zero virus attacks on OpenVMS
-

Since Microsoft operating systems originally were focused at the single user environment, security technology within Microsoft O/S systems and applications had to be built in as they moved to support servers. While security and authentication has improved in recent years, they still lag behind more traditional enterprise level operating systems.

It is recommended that any MS based server be put behind a firewall to aid in protecting the system from various network attack strategies.

6.1.2 Availability

While Microsoft does not have the same level of application runtime fail-over as OpenVMS and UNIX, it can provide box level fail-over restart of applications. In the web services environment, the user experience is typical of browser refresh or reconnection.

6.1.3 Batch Process

Third party applications and VB can be used to replicate batch processes, but they are not built into the operating system and are typically not as robust as Unix and OpenVMS batch systems. While the command language interface has improved in recent years to aid in processing data center types of operations, most processes on Microsoft tend to operate at the same priority level, so interactive jobs will be competing with batch process at the same rate of resource consumption.

This author does not have any performance benchmarks on batch operations on Microsoft, but going back to 32 bit processing with faster processors may match the performance of your existing 64 bit systems.

6.1.4 Web and GUI development tools

MS Web and GUI development tools offer easy to use IDE for VB script, and Active Server Page generation. While the .NET and SOAP promotion is very active, .NET may be a bit premature (bleeding edge technology) to pursue at this time. The one drawback to MS Web interfaces is their reliance on 32 bit PC and server platforms and Microsoft’s reluctance to use the Java standard that is platform independent.

6.1.5 Office and Data Integration

Microsoft is the top end-user environment with MS Office providing seamless integration to Word processing, spreadsheet, drawing, database, email, and multi-media applications.

- ODBC provides reliable connection to MS and competitor databases. Active directory provides a secure connection to MS and competitor directory structures. COM and DCOM allow VB to provide customized and automated business solutions with the MS Office suite.

6.2 Migrating User interfaces to Microsoft

Typical User interfaces in Microsoft can be implemented as standalone applications in VB or C/C++, as web-based active server pages (ASP), or .NET applications. Interfaces can also be to COM server objects through any of the Microsoft Office applications. ASP interface implementation is the most common, especially in a protected intranet environment to integrate access database records, flat files, and reports. XML, XSL and SOAP help in expediting data and displays for thin clients.

Secure Sockets (SSL), XML, and .NET promise to improve the security of user information

In the current CSS implementation, user interfaces are constructed with Axiant, the 160 screens will have to be re-written in either active server script, Vbscript, Javascript, or Java. Whether implemented in Microsoft or Java based tooling, this is a substantial amount of change on the existing CSS environment.

See section 5, on “Migrating off of Axiant tooling”

6.3 Migrating business logic to Microsoft

Since the current OpenVMS Cobol is using the ANSI standard compilation switch, it is our expectation that most of the Cobol should migrate directly through recompilation.

Based on our statistical analysis of the sources, our expectation is to have 8-10 minor migration issues that will require some code modification.

6.4 Migrating batch process to Microsoft

Recasting DCL into VB can be done with some automation by using search and replace scripts. However, there are approximately 2000 references to eighteen different types of system calls (lexicals). An abstraction layer for the eighteen lexicals will need to be created to call MS functions to mimic the VMS call and return values.

7. Migrating Databases to Microsoft

MS SQL Server, while being a very reliable and high performance database, cannot compete with the performance, security, reliability, or scalability of Oracle database systems.

Furthermore, there is a trend in the industry to use the near real-time and simultaneous update and retrieval and analysis of database records to recast batch processes into continuous runtime applications. Reengineering to using an ODS Operational Data Store could make the printing of bills and other batch oriented jobs less reliance on a batch window.

There are no known migration tools for directly moving RMS files into other relational database systems, whether they are Jet, Access, SQL Server, or other database systems. However, a script and small VBA[1] application could be created to convert FDL files into database tables.

If existing data from these RMS files are also needed. The following steps will be required to migrate the data. The VMS CONVERT/EXTRACT utility can be run to extract the data as sequential text files. After the database tables have been established, an

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[1] All Micrsoft office applications are supported with a resident Visual Basic interface for macros and customization. This resident Visual Basic is known as VBA

additional script and VBA application will need to be created to load the tables with the sequential text file data.

While moving all of the RMS files at once to a relational database sounds like a reasonable approach, it does mean the replacement of all RMS calls in the entire source modules will have to be done at the same time to complete the migration of these data. This does incur risk at a systems level, because so much change is incurred in the system at one time.

If the migration were to be done in a phased approach, a tool like Attunity could be used to continue to access RMS files on the existing OpenVMS system. Over time, individual RMS files could be incorporated into a larger Oracle database system and procedure calls could be implemented to replace the existing RMS calls in the existing source code modules.

8. Migrating application environment to HP-UX

8.1 Tradeoffs and Advantages of HP-UX Environment

If there is one advantage to Unix environments it is the access to multi-vendor supported Open Standards in languages, Interfaces, and Web communications.
HP-UX is the most popular enterprise level Unix operating system on the market. It is expected by 2005 that HP-UX 11i version 3 will include the best technologies from the Tru64 UNIX operating system; Tru Cluster support and the Advanced File System (AdvFs). The Advanced File System improves the reliability and recovery time from system failures. Tru Clusters provide improved performance and capacity scaling and high availability.

8.1.1 Security

Generally, security on Unix systems is in tighter control than Microsoft at this time. Various Unix systems and more widely used applications (web browsers) continue to come under attack, but not at the frequency or severity that Microsoft products have received.

8.1.2 Availability

Current HP-UX has fail-over capability, but not the same level of application availability as Tru Clusters. However, HP-UX is being upgraded to take the best technologies from Tru64 UNIX and will eventually support cluster operations and the advanced file system.

8.1.2 Batch Process

Unix systems perform batch using shell scripts. HP-UX can operate under several different shell scripts. There are third party and OpenSource batch processors that will provide load sharing on the Unix platform.

8.1.4 Web and GUI development tools

HP-UX and Unix in general share a wealth of tools in the OpenSource software environment including Web Servers, Web Browsers, and Java[2].
There are several OpenSource and Web standards that can be used to implement User interfaces. Java and the J2EE runtime environment have similar look and feel as the Microsoft visual programming tools.

With the use of XML and Java, user interfaces can be web enabled, platform independent, and easily migrated to other system platforms, if needed.

Unix also supports a number of GUI interfaces when directly connecting to the platform system including X, Motif, Common Desktop Environment, and KDE.

8.1.5 Office and Data Integration

HP-UX and Linux systems have followed the lead set by Microsoft. OpenSource supports OpenOffice, which is a similar user office environment to MS Office. Tooling and system support operations of the HP-UX system is GUI based. Furthermore, OpenView allows a single GUI interface to all nodes on the intranet (OpenVMS, UNIX, NT,…).

8.2 Migrating User interfaces to HP-UX

While Microsoft has more flexibility in the development of standalone interfaces to data and integrated office objects; Java development and deployment is on par with the Visual development environments and is vendor independent. Java and Javascript integrate very well with XML, XSL, and other web standards.

In the current CSS implementation user interfaces are constructed with Axiant. The 160 screens will have to re-written in either active server script, Vbscript, Javascript, or Java. Whether implemented in Microsoft or Java based tooling, this is a substantial amount of change on the existing CSS environment.

See section 5, on “Migrating off of Axiant tooling”

8.3 Migrating business logic to HP-UX

Since the current OpenVMS COBOL is using the ANSI standard compilation switch, it is our expectation that most of the Cobol should migrate directly through recompilation.

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[2] Java is a Platform independent Application Development Language. J2EE is the platform independent development environment. And, JavaBeans is a high level programming abstraction of the more common algorithms used in developing applications.

Based on our statistical analysis of the sources and a migration from OpenVMS to HP-UX, our expectation is to have less than 8 minor migration issues that will require some code modification.

8.4 Migrating batch process to HP-UX

Recasting DCL into one of the Unix shell scripts can be done with some automation using perl or awk scripts. However, there are approximately 2000 references to eighteen different types of system calls (lexicals). While most system calls can be duplicated with equivalent Unix calls or piped calls, a few of unique OpenVMS lexicals may need to be abstracted into a C or perl routine to mimic VMS call values.

8.5 Migrating the databases to HP-UX

There are OpenSource databases and ISAM file support on Unix systems, but our recommendation is to use Oracle for enterprise level database support. It is multiple platform supported, scalable, reliable, and highly available.

As stated earlier in the Microsoft database discussion, there is a trend in the industry to use the near real-time and simultaneous update and retrieval and analysis of database records to recast batch processes into continuous runtime applications. Reengineering to using an ODS Operational Data Store could make the printing of bills and other batch oriented jobs less reliant to a batch window.

There are no known migration tools for directly moving RMS files into other relational database systems, however, Oracle's SQL*Loader can be used to create database tables. A perl or awk script could be created to convert FDL files into scripts suitable for SQL*Loader to create the database tables.

If existing data from these RMS files are also needed. The following steps will be required to migrate the data. The VMS CONVERT/EXTRACT utility can be run to extract the data as sequential text files. After the database tables have been established, an additional perl or awk script could be created to load the tables with the sequential text file data using the SQL*Loader utility.

While moving all of the RMS files at once to a relational database sounds like a reasonable approach, it does mean the replacement of all RMS calls in the entire source modules will have to be done at the same time to complete the migration of these data. This does incur risk at a systems level, because so much change is incurred in the system at one time.

If the migration were to be done in a phased approach, a tool like Attunity could be used to continue to access RMS files on the existing OpenVMS system. Over time, individual RMS files could be incorporated into a larger Oracle database system and procedure calls could be implemented to replace the existing RMS calls in the existing source code modules.

9. Migration Sizing

Although HP was not able to perform a two-day assessment workshop, HP was able to obtain a copy of the CSS application sources, DCL scripts, and Axiant's PowerHouse source code from Newfoundland Power to analyze its size and complexity and determine a worst case estimate.

Sizing Assumptions

- Migration work does not include re-architecting the environment or the application, the migration effort assumes the same basic application functionality once moved to the new platform
- Sizing is based solely on the source code collection supplied by Newfoundland Power.
- Sizing is based on screen counts, build and test information supplied by Newfoundland Power referenced in Appendix B
- HP assumes that Newfoundland Power will assist in duplicating the CSS environment and application at HP. This system is to act as a reference site during any migration project as a migration test reference system
- HP assumes a migration verification test can be constructed from existing system validations and user verification tests created/owned by Newfoundland Power

Estimate to reengineer Axiant Powerhouse source files and eliminate the dependence on PowerHouse and migrate DCL batch, Cobol, and all other related applications is
1000 engineer-days of effort on either Unix or Windows platforms.

Estimate to migrate all applications and continued use of Axiant/Powerhouse is
300 engineer-days of effort on either Unix or Windows platforms.

This sizing estimate currently does not include

- on site training for Newfoundland engineers for operations and software development (e.g. Web, Unix, or MS training)
- hardware acquisition and deployment costs
- software licenses and support costs
- any maintenance or post project activities
- Newfoundland engineering time or project management
- Operations and user-impact and retraining

Appendix A - Source Code Analysis and Statistics

A.1 Source Code Statistics

dataset	dataset id	File Count	Total NCSS	Total Lines	Total Commentlines	Total Complexity	Total Volume
dcl	13	1369	58049	135550	76787	6124	1913.36059914807
Cobol	14	239	112859	239554	89655	7038	3915.46771401135
PreCOB	15	385	353611	688116	189670	15448	13127.7170694178
Sort	16	8	64	64	0	8	3.49026725691973
SQL	17	4	737	836	10	28	39.7269881447419
COB_LIB	18	598	15515	23486	7069	884	640.460546847298
FDL	19	151	4331	4958	0	151	51.3964024667489
PowerHouse	20	804	44798	56269	0	1251	2905.77238593677
Power_Forms	21	11	784	972	0	11	33.0673318141293
Powerhouse_Def_lang	22	7	23736	33600	0	12	1979.46907639642
SMR	23	1	7	7	0	1	0.250251420376034

A.2 Software metrics and Statistics

When we do a code assessment we want to determine how big a module is and how complex the module is. The module size. We use three common software engineering measures to determine size:

- non-comment source lines(NCSS)
- volume
- complexity

A.2.1 NCSS

Non-comment Source Statements is a count of those source code statements in a module that are not comments. When we refer to "Lines of Code" we are referring to non-comment source statements.

Using NCSS as a measure of size does not account for multiple operators/commands in a source statement or the number of unique data types and variables (operands) used. It doesn't tell you the number of different operations/commands that are used. It doesn't tell you how many operations the module does or how often it uses the operands.

A.2.2 Code Volume

The volume metric we use is a better measure of the operators/commands and operands used. It can be viewed as a measure of the richness of the Language used, how many different commands used, how many total commands, how many different operands used and how often they are used. It is a measure of the amount of information represented in the module. The volume metric we use is the Halstead Volume Metric.

While the Halstead Volume Metric does give you a measure of complexity in the volume of information in the module it doesn't tell you about the structure or logic of the module.

A.2.3 Code Complexity

The complexity of the module. We use the McCabe Cyclomatic Complexity Metric to measure complexity. This metric assess the control flow through the module. It measures the number of decisions/branches made and how many of these decisions/branches are interconnected. The more decisions and the more interconnections the more complex the module is.

These metrics have been used by the Carnegie Mellon University's Software Engineering Institute, NASA's Software Assurance Technology Center, The US Army and many commercial firms. The Software Engineering Institute, the Software Assurance Technology Center and The US Army have published papers on the correlation of the Halstead and McCabe metrics to the maintainability and reliability of software. It is our experience that these metrics and their ratios are excellent indicators of the complexity of the code, it's reliability, how well it has been maintained and the ease in migrating the modules.

The distribution of the volume of the modules is one indication of ease of maintenance. Remember volume is a measure of the amount of "information" in a module. The more information in a module the more difficult it is to comprehend therefore more difficult to maintain.

When you plot the volume of the modules (log of) against the cumulative number of modules you should see a line sloping upward to the right which truncates in the 70th percentile with only a few points beyond .

One of the ratios we use is complexity density. Give the volume of the module how much logic is packed into it. The larger the module volume the less dense it should be. Large modules containing a large amount of logic are more difficult to write, debug, maintain and migrate. We therefore look at the distribution of the modules with respect to their complexity density.

Well structured applications keep the complexity in any one module to a density less than 2. Although it usually is impossible to completely avoid higher densities the number of modules with densities greater than 2 should be small. If you graph the module density (log of) against cumulative number of modules you should see a line sloping upward to the right which truncates when the density exceeds 2. You should see a small number of points beyond density 2.

Some problems are more complex than others and therefore the modules
Solving these problems will have higher complexity densities. However by plotting the complexity density (log of) against volume (log of) we get an indication of how the logic and functions of the application where divided up, packaged. This graph has a very definitive base line, (slope=1) that slopes from top left, very complex modules with small volume, to bottom right, large volume less complex modules. The points to the right of the base line should form a triangle. The angle formed by the base line and the far right side of the triangle is an indicator of reliability. The smaller the angle the more reliable the modules. The closer to 90 degrees the angle becomes the less and less reliable the code.

A.2.4 Complexity Density

We use the volume metric, the complexity metric, complexity density (complexity/volume) and graphs of their relationships to assess the reliability of the code, how the code has been maintained and the degree of difficulty to migrate the code. Our experience has been that these metrics and graphs are very accurate in pointing out modules that have been difficult to maintain, which modules are currently causing the most problems and which modules will be difficult to migrate.

1. Halstead Volume Metric

   n1= number of distinct operators/commands.
   n2= number of distinct operands/variables.
   N1= Total number of operators/commands.
   N2= Total number of operands/variables.
   Program Vocabulary n=n1+n2.
   Program Length N=N1+N2.

   Volume= N*log(n)

2. McCabe Cyclomatic Complexity Metric

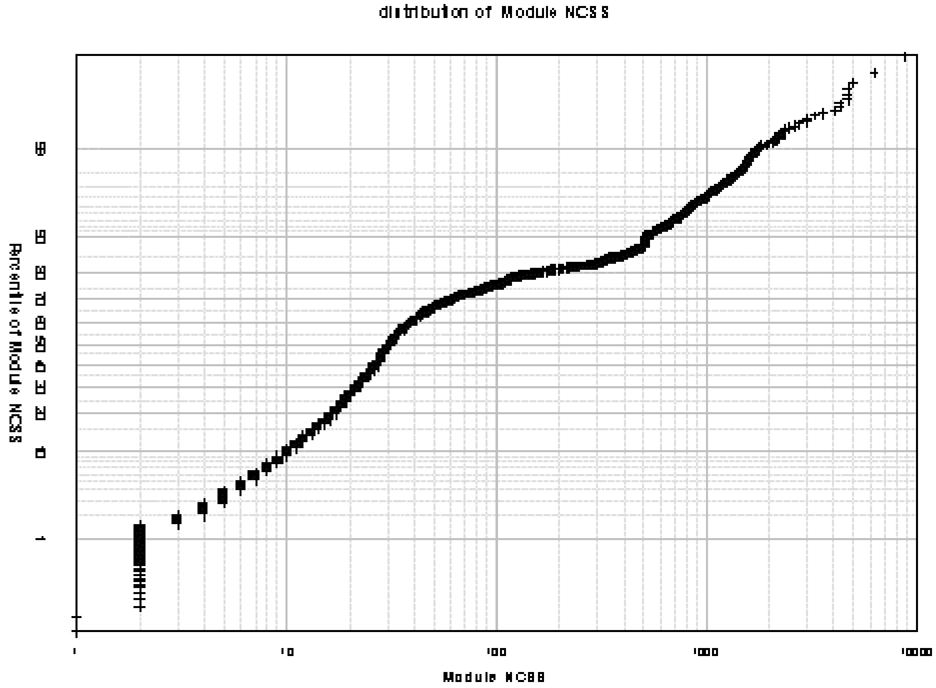
This metric is computed from a connected graph of the module (topology of the control flow within the module).

E= number of edges of the graph.
N= number of nodes in the graph.
P= number of connected components.

Cyclomatic Complexity Metric= E-N+P

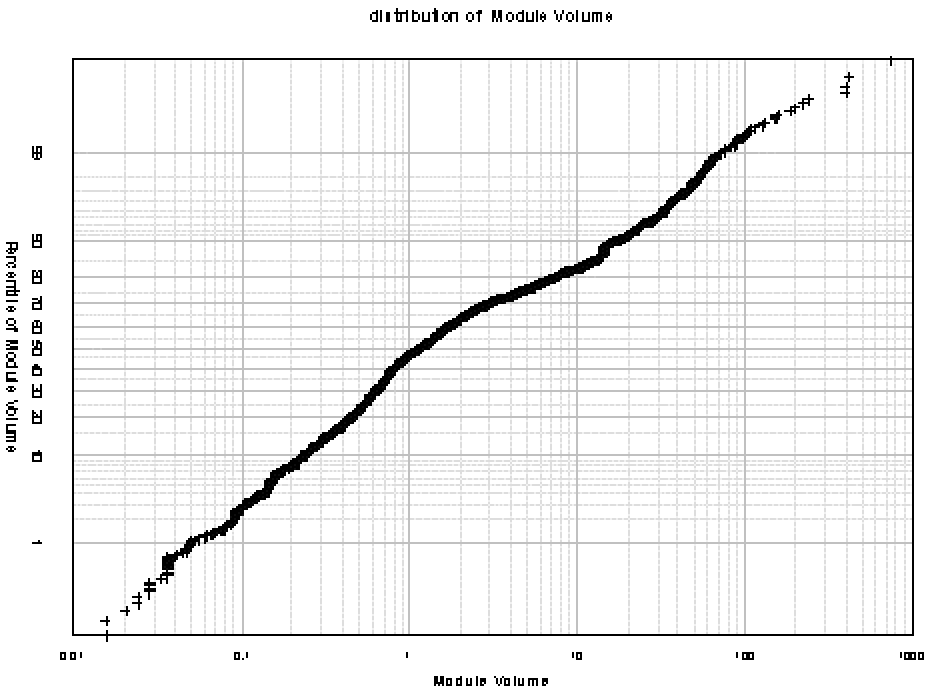
A.3 Code Analysis

A.3.1 Distribution of Module NCSS



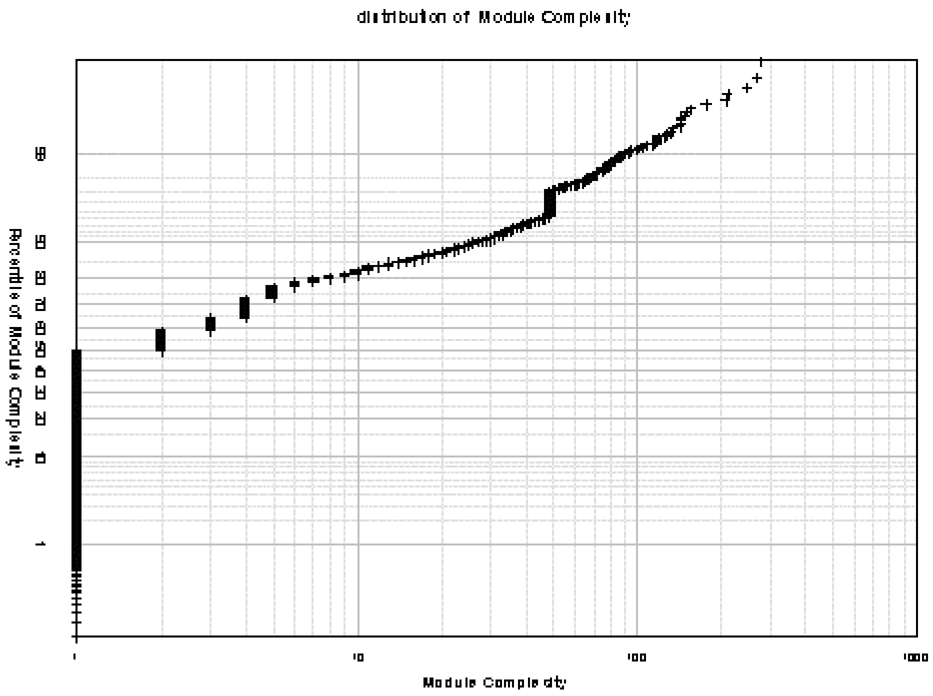
NCSS 80% at 200ncss with plateau, but last 20% rises to 10,000. Module volumes of 200 ncss is indication of following a design and development practice in a waterfall development process. While the 80% plateau indicates a regimented architecture and design, the 20% high slope is indicative of a long term maintenance practice that never revisited or never given time to permit adaptations to base architecture. Maintenance/re-architecture effort will be impacted 15%

A.3.2 Distribution of Module Volumes



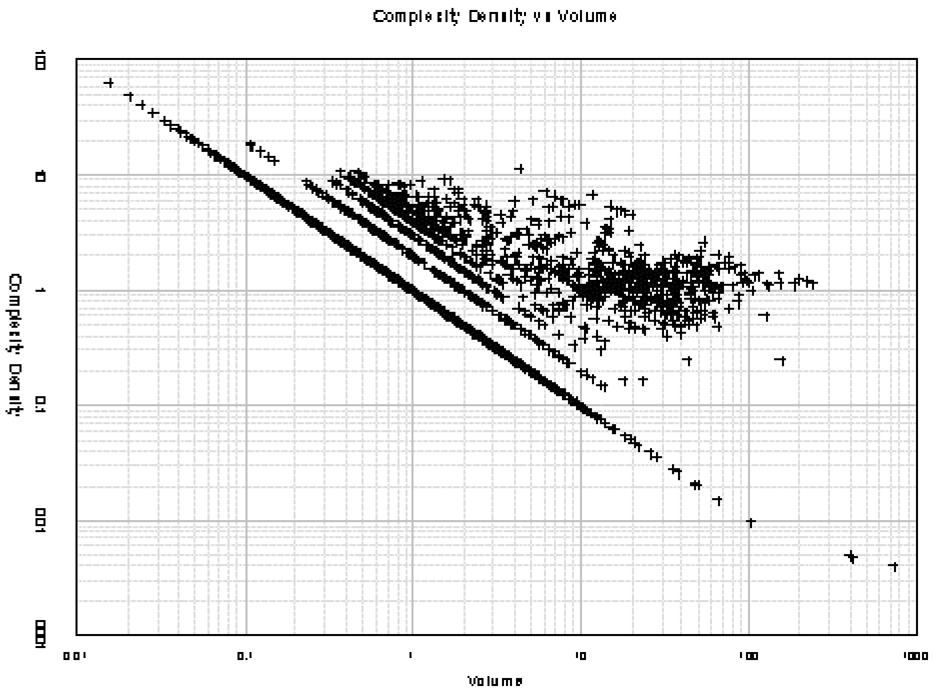
Halstead Volume at 80% of modules at 8, this is a typical value for controlled environments. In this case, the Halstead Volume and NCSS closely match.

A.3.3 Distribution of Module Complexity



The large bands on the left are indicative of large numbers of declarative files (record structures and other formatting and setup files). 80% of the modules are at or below the McCabe complexity of 10, which is indicative of trying to limit module complexity. This is an aid to maintaining or migrating code.

A.3.4 Complexity Density versus Volume



Appendix B – Other CSS Application Migration Data Points

1. How many RMS files currently support the environment - 1350 rms files - roughly 4 gigs
2. What is standard switch do they use on fhe OpenVMS Cobol - ANSI
3. If migrating off of Axiant is part of this estimate
   - how many screens are currently supported? - approx 160, today
   - approx number of concurrent screens opened - 15
4. When was the last time the entire software environment was rebuilt?
   Full on-line was rebuilt for an application upgrade last week. Full batch was approx 1 year ago. In the last year the full application was re-compiled through various projects and enhancement efforts.
5. Is the total software build process documented? Yes - THere are build scripts for the procobol/cobol and the Axiant is compiled from the repository with the native powerhouse compoiled on the server. I do believe we have scripts for everything. I can confirm.
6. Is there a test process, tools, or test harness to validate the current production system? –

Development environment utilizes a Development/Test/Prod approach. Unit testing is ad-hoc and is performed in the development environment.
Functional testing is formal (test plans are developed) for most changes whereby test plans are created and test data is identified/created usually by extracting live data from the production area (a procedure in place to do this) and put into the test area.

For almost all of the online functionality and most of the core Batch processes there is a functional specification for each conversation or major batch module. For a subset, but most of these processes, functional test plans are in place as well. These test plans are used as templates for development of test conditions for new or changed functionality. The analyst based on the scope of the change determines how much of the full test plan to execute for the new functional test.

Integration, regression and performance testing is performed as required.

The disaster recovery site is used for these types of testing. To test the batch procedures system back-ups are recovered to the DR environment (which is an exact copy of production in almost every respect - CPU, database etc. type and size). Specific information is identified for before and after checks as required. Batch processes are ran with timings taken and both broad checks (number of bills, report totals, journal entry totals etc.) and specific checks where identified are completed. Online performance testing is extremely rare for level of change and when performed is done manually in the DR environment. No online testing tools are in place. We used Visual Test in the last technical migration (COBOL/Install/1 to Axiant/Powerhouse) but because of the nature of Powerhouse it was very manual intensive to set up.

There is no repository of test data or a regression test environment (with predefined test data) for the overall system.

For rate calculation and bill presentation only, there is a small regression test environment (called CATS) with predefined test data and refresh and execute procedures.

There is a bill checking excel spreadsheet environment which is used to download a sampling of bills each day and check them for accuracy. This is sometimes used to assist testing.

We are strong proponents of a release strategy where we batch up changes into a release usually once per month bust sometimes weekly.

In terms of time it takes to perform the various tests it varies on scope of changes.

The client group is very mature with respect to testing methodology.
Traditionally IS performs all testing accept User Acceptance test however we have a number of client analysts who perform functional testing now as well.

We never have the same person performing a functional test and an acceptance test.

Typically because the system is quite stable Integration test, Performance testing and Acceptance testing are completed together however if we have specific performance or integration concerns we complete this testing separately or with functional testing.

Hardware and System management tests are rarely required and are based on scope of change. When we add a new CPU or some other module we will install in Disaster Recovery environment first and run batch processing etc and check. Having said all of this the existing procedures will have to be re-developed/modified for the new environment and this is a significant part of the effort.

Appendix C - A Security Timeline On Microsoft Software

This timeline is based on a number of articles from eweek, The Inquirer, C/Net News, and the Gartner group.[3]

June 18, 2001 - Microsoft reveals Web server hole
vulnerability lies within the code that Microsoft's IIS server uses to support indexing, a feature that speeds searching on Web servers[4]

July 19, 2001 - First outbreak of Denial of Service attack on IIS servers

Sep 18, 2001 - Nimda work DOS attack on IIS servers

Sep 19, 2002 - Gartner recommends moving off of IIS servers[5]
This move should include any Microsoft .NET Web services, which requires the use of IIS

May 3, 2002 - C/Net "Code Red still threatens Net "
Code Red and its two variants use a security hole in IIS

Aug 19, 2002 - Microsoft Security Under Fire
Twice in the past three weeks, experts have issued reports of security flaws in Microsoft products, and both times the company remained silent, making no immediate public comment and issuing no fix.

Aug 20, 2002 - researchers find a new flaw in Microsoft Corp.'s SQL Server database software.

Jan 3, 2003 - Yaha worm - DOS attack on MS email servers

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[3] www.eweek.com, www.gartner.com, www.theinquirer.com www.news.com

[4] . The module, known as the Indexing Service ISAPI Filter, does not properly check for buffer overruns, a common problem in software. Maiffret estimated that at least 50 percent of all IIS servers--about 3 million--still have the default component installed and are thus vulnerable.

[5] Gartner recommends moving off of IIS servers that enterprises hit by both Code Red and Nimda immediately investigate alternatives to IIS, including moving Web applications to Web server software from other vendors, such as iPlanet and Apache.
Gartner believed that rewriting of IIS would not occur before year-end 2002 (0.8 probability).

Appendix R - Sector7 Technical Migration Assessment External

Sector7

NORTH AMERICA • EUROPE • ASIA PACIFIC

Budget and Planning Estimate to

NEWFOUNDLAND
POWER
A FORTIS COMPANY

Re-Hosting of Customer Service System (CSS)
from HP Alpha OpenVMS 7.2.1 to HP HP-UX

Date: 27 May 2003
Revision: 1.6

Contact: Lyman Lundquist (Lyman_Lundquist@sector7.com) +1-512-340-9717

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1 Definitions

‘Sector7’ refers to Sector7 USA, Inc. and/or Sector7 (U.K.) Ltd.

‘NFP’ refers to Newfoundland Power Inc. of St. John's, NF Canada

‘CSS’ refers to NFP*’s* Customer Service System application

‘Time and Materials’ or ‘T&M’ means actual hours worked will be billed at a pre-determined rate on bi-weekly basis

‘Fixed Price’ means client will be billed at each payment milestone date for a pre-determined amount. Billing is not based on actual hours worked

2 Executive Summary

Sector7 is pleased to present NFP with a Budget and Planning Estimate for Sector7's effort to provide services to port the CSS application(s) owned/developed by NFP from HP Alpha OpenVMS 7.2.1 to HP HP-UX.

Sector7 is partnering with NFP to make the re-hosting of the CSS application very cost effective — with minimal risk. Software migration is a complex process that requires meticulous planning. Platform migrations are a specific competency, comprising complex engagement managers, powerful migration tools, migration skills, and hardware and packaged applications, all of which Sector7 is able to provide.

2.1 Introduction

Newfoundland Power Inc. operates an integrated generation, transmission and distribution system throughout the island of Newfoundland, and serves approximately 220,000 customers in 600 communities. These customers constitute 85 per cent of all electrical consumers in the province.

Sector7 has been providing application re-hosting and renovation solutions for companies needing new hardware technology that maximize their software investments since 1985. The Sector7 Professional Services Group has been involved in porting projects for many of the top companies in the world. Our broad range of experiences allows us to effectively help in all aspects of a porting project from the business case to the most detailed technical problem.

Sector7 is one of the world leaders in "Preserving software investments through cost-effective, low-risk migration." Until recently, migration was either too costly, involved laborious re-engineering, or there were no tools available.

Sector7 have devised a five-step process that efficiently coordinates every aspect of a migration. We begin with an in-depth analysis of your current environment, establish a road map for each component then outline a detailed "start-to-finish" solution that guides you through migration and systems integration. Each stage of this proven "Blueprint" process is designed to build upon the previous stage and move seamlessly into the next. Sector7 has performed numerous migrations using this process

2.2 Our Understanding of the Business Problem and Opportunity

NFP utilizes a number of corporate applications that run on OpenVMS. This platform is no longer part of NFP's long-term target architecture strategy, and so they are reducing dependence on this platform through replacement of systems via package acquisitions, re-development and technical migrations. The Customer Service System (CSS) is by far the largest corporate application running on the platform today.

Developed in house, the Customer Service system (CSS) provides NFP's primary accounts receivable and direct customer billing for electrical sales. It consists of cash, customer billing, credit and collections, accounts receivable, service orders, processing meter reads, inquiries, data maintenance, and reporting modules.

NFP is interested in examining all viable approaches to a technical migration of CSS within two basic alternatives:

1. Move the existing CSS from the OpenVMS platform to a new platform(s) while keeping major technology components (e.g. keep COBOL, Powerhouse, Axiant etc.).

2. Move the existing CSS from the OpenVMS platform to a new platform(s) while redeveloping major technology components according to the Company's Target Technology Architecture (Wintel with .net technologies)

The results of this Budget and Planning Estimate will provide NFP with the means for approval to move forward with a Sector7 Stage One or Stage Two Assessment, which will assist in determining their on-going strategy for platform replacement.

2.3 Migration Approach Overview

While NFP is interested in examining all the viable approaches to the migration of CSS within the two basic alternatives described above, this Budget and Planning Estimate specifically addresses option (1) - Move the existing CSS from OpenVMS platform to a new platform while keeping major technology components (i.e. keep COBOL, Powerhouse, Axiant). This approach reduces risk by virtue of reducing the amount of re-engineering required to make this transition. Reduced risk greatly increases the opportunity for project success and positions CSS on the new platform so that subsequent redevelopment of major technology components can safely take place.

Sector7 does not recommend option (2) because in Sector7's experience the re-engineering required to re-architect an application such as CSS towards Microsoft .Net technology is so large as to virtually constitute a complete re-write. This is therefore an extremely high-risk strategy, one which often suffers "scope creep" as technologies change during the lifetime of a long project, presenting a moving target and making it almost impossible to reach a satisfactory end.

2.3.1 Target Platform

In Sector7's experience, upwards of 95% of OpenVMS installations choose UNIX-based platforms when migrating. This is because UNIX is a true multi-user system, whereas Windows is not. That is, Windows is designed to be used by one person at a time. Databases running under Windows allow concurrent access by multiple users, but the Operating System itself is designed to deal with a single human being at a time. UNIX is designed to handle multiple concurrent users and therefore matches the architecture of OpenVMS. Windows is designed with fat client/server architecture in mind. There is however a multi-user version of Windows called Terminal Server (TSE).

On TSE and multi-user Windows systems from commercial companies such as Citrix and others, the Windows NT kernel is modified to allow each session to create a complete virtual machine execution space for each new session. This means the entire Win32®-based subsystem gets "cloned" for each new session and a dedicated section of memory and other resources are reserved for each new session. Each user runs their session in a protected virtual machine on the server and has access to their own virtual memory and devices. While the virtual machine concept is technically viable, there are issues with resource consumption. Since each user needs their own virtual memory space, typically a minimum of 20-40 megabytes of RAM is required for each session that is hosted on the server. If the user is running large memory intensive applications, even more can be required. The result is that most large installations of TSE run with what has come to be known as "server farms." Companies install multiple systems with TSE and load-balance users across the multiple networked servers. As more users join the network, additional servers can be added to take up the load. The obvious disadvantage is the tremendous cost in hardware system resources.

2.3.2 CSS Architecture

The on-line parts of CSS are developed using Cognos Axiant 4GL deployed in thin-client mode, which means that while the user-interface processing takes place on the client, the application and data processing are on the server. Indeed, CSS is heavily reliant on server-side COBOL programs called from the on-line Axiant screens – these contain much of NFP's business rules and logic.

In Sector7's experience, a server-biased application such as CSS with high on-line user concurrency (100 users for CSS) and a heavy batch processing (10 hours/night for CSS) sits better on a UNIX-based database server such as HP HP-UX rather than a Microsoft platform such as Windows 2000/XP, due to the architectural differences between the two platforms outlined above.

NFP has expressed interest in changing from Oracle RDBMS to Microsoft SQLServer. Sector7 believes that this would be a major re-engineering effort because the existing CSS code is very heavily reliant on embedded SQL (Oracle Pro*COBOL) and SQLServer does not support Embedded SQL well (see Appendix C). NFP has further expressed a strong desire to re-engineer CSS to Microsoft .net architecture.

In relation to both these points, Sector7's experience is that re-engineering while migrating is a very high risk strategy prone to failure: typically, the amount of time, effort and funding required is severely under estimated while on-going technology advancements and business change present a moving target and thus a never-ending project. Testing a re-engineered application on a new platform is particularly fraught as it is virtually impossible to create consistent test data comparable test cases between the source and target systems.

To re-engineer an CSS for SQLServer means, in practical terms, stripping out all EXEC SQL statements and replacing them with API calls to the SQLServer ODBC API. The cost of this re-engineering is proportionate to the number of embedded SQL statements contained in the CSS COBOL, plus additional costs for the analysis and re-design of the data access methodology. Please refer to Appendix C for a more detailed discussion of this topic.

CSS is heavily dependent on the VMS DCL command language, and NFP has expressed a desire to "go native" with regard to command procedures on the target platform. However, Sector7 would recommend using its VX/DCL DCL emulator as this enables the CSS DCL procedures to be moved quickly and cheaply to the target platform – refer to Appendix B for details.

2.3.3 Summary

In consideration of the above, this Budget and Planning Estimate focuses on a "like-for-like" migration of CSS from HP OpenVMS to HP HP-UX while keeping major technology components of COBOL, Powerhouse, Axiant, DCL, etc.

However, Sector7's approach in selecting open technologies such as MicroFocus COBOL and Oracle RDBMS will allow NFP to defer the final deployment decision until the port to HP-UX is completed.

In this way, the port to HP-UX can be seen as moving CSS onto a "spring board" platform, ready for any future developments and technologies as NFP may choose.

2.4 Schedule & Pricing

When creating a Budget and Planning Estimate to re-host an application, we apply the experience and knowledge gained from prior projects to develop an estimated Schedule and Price.

The assumptions and determinations within this document are based on the information, application metrics and any source code provided to us by NFP – we have not performed an in-depth analysis of any code supplied. Any deviations in the information provided to Sector7 that affects Sector7's understanding of the application, application metrics, or portability of any third-party products mentioned in this document might impact the estimated Schedule and Price specified.

Based upon our current understanding of the project scope and requirements from NFP and the migration approach described above, our Budget and Planning Estimate is shown in Table 1.

Table 1 – Budget and Planning Estimate

Name/Nature of Application	NFP / CSS
Current Platform	HP Alpha OpenVMS 7.2.1
Target Platform	HP HP-UX
Liability	This is a Budget and Planning Estimate for a Time & Materials effort
Estimated Duration	7 to 9 calendar months
Estimated Price Range	US$720,000.00 to US$905,000.00 excluding Sector7 VX/Tools licenses

Figure 1 – Breakdown of Project Costs including Project Management

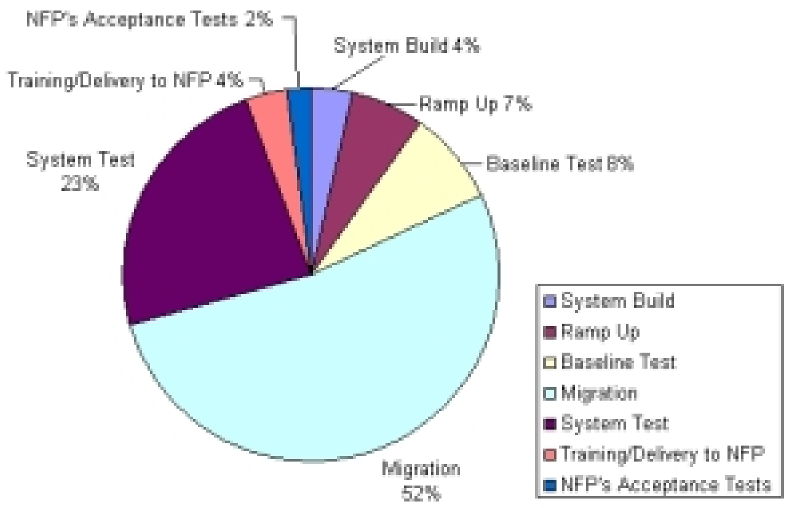
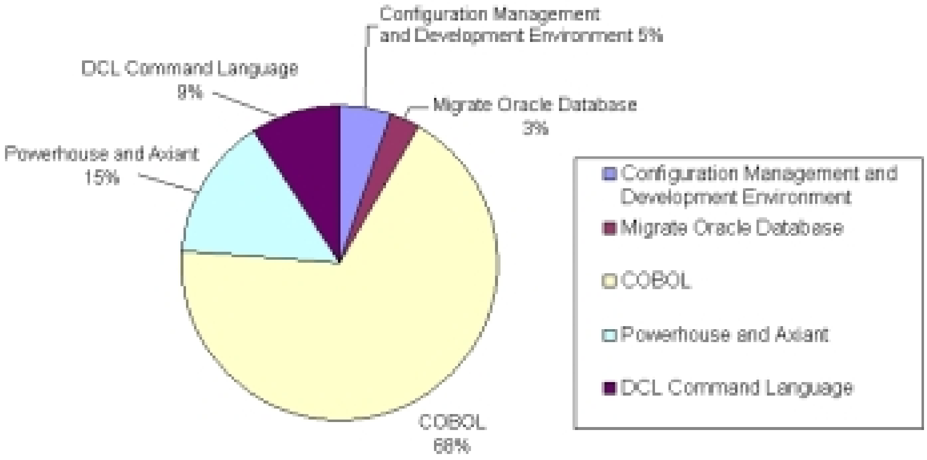


Figure 2 – Breakdown of Migration Costs including Project Management



2.4.1 Sector7 VX/Tools Pricing

Sector7 is recommending usage of the following elements of its VX/Tools suite of migration tools. Please refer to Appendix B for a full description of these products. Note that maintenance for the first year is mandatory.

Product Name	Cost of 4-User Development License	Cost of Unlimited User Run-Time License	Cost of Annual Maintenance
VX/DCL	N/A	US$10,000.00	20% of license fee
VX/JSP	N/A	US$5,000.00	20% of license fee
VX/RT	US$35,000.00	US$20,000.00	20% of license fee
VX/RMS	Included in VX/RT	Included in VX/RT	Included in VX/RT
TOTAL	**US$35,000.00**	**US$35,000**	**TOTAL: US$70,000**

Note: where possible, CSS' usage of VMS System Services will be migrated native HP-UX equivalents. Alternatively, Sector7 may use its VX/RT library to replace these calls. This determination requires additional analysis.

2.5 Recommendation/Next Step(s)

Depending on the requirements of NFP, there are three options to be considered as the next step:

- Initiate the migration project on a Time & Materials basis as described in Table 1
- Perform a Stage One Assessment to determine the order of magnitude price and duration for the project. Typically this takes 6-8 weeks and we can provide a T&M estimate to within ±30% of the final price. There will be a fee of US$30k charged for the Stage One Assessment, however, a portion of this fee will be waived if the migration project is awarded to Sector7.
- Perform a Stage Two Assessment to determine a fixed price and schedule for the project. Typically this takes 8–10 weeks and there will be a fee of US$100k charged, however, a portion of this fee will be waived if the migration project is awarded to Sector7.

3 Project Approach

3.1 Introduction

Sector7's approach to the migration and implementation of NFP's application is driven by an integrated methodology, offering proven Project Management and technical delivery methods. The focus of our approach is to provide high-quality deliverables within the schedule and budget committed.

In this section, we will describe in more detail each of the following:

- Project management roles and responsibilities
- A phased approach
- Risk management
- Quality assurance
- Critical success factors
- Benefits of re-hosting
- Teaming

3.2 Project Management Roles and Responsibilities

Effective project management (PM) is probably the most critical skill required to implement a successful project/solution. Sector7's project management approach follows consistent, well-defined processes, and has a proven track record in delivering results. At Sector7, we recognize project management as a core capability and our service professionals, who have chosen this career path, are held to very high standards and expectations.

The keys to Project Management are demonstrated leadership, high productivity, effective communications, and the ability to properly manage the following activities within the framework of the project.

- Detailed project planning, which allows for high-confidence in project schedules and estimates
- Closely tracking project activities against the project plan, so that course corrections can be applied quickly, if needed
- Ongoing management of project issues and risk contingency plans
- Quality assurance and deliverables management
- Tight scope and change management disciplines
- Daily management of project concerns, team chemistry, and morale management
- Accurate reporting of results that are achieved

In addition to Sector7's methodologies and capabilities, Sector7 project managers are also highly skilled in the use of PM and tracking tools, such as Microsoft Project. In summary, our experience has shown that the combination of methods, capabilities, and tools consistently yield positive results.

3.3 A Phased Approach

Sector7 is recommending a multi-phased approach to the development and implementation of the migrated CSS application. We believe that this approach provides reduced risk and increased opportunity for project success.

Step One – Migration Assessment

The Migration Assessment provides an initial assessment to determine the rough order of magnitude price and duration for a project. This stage determines the project scope.

The entire environment is reviewed for porting to the desired platform. Sector7 will review the software components such as; language, databases, user interfaces, communications and COTS software.

Step Two – Migration Planning

Migration planning focuses on gaining a comprehensive understanding of the migration pursuit, and concludes with a refinement of the original budget and planning estimates provided. The primary tasks performed during this phase are additional application and database analysis, detailed project and test planning, and validation of our readiness to enter phase three. This activity can be performed separately, or as a component of the migration project itself.

Steps Three, Four & Five – Migration, Testing, and Deployment

Migration, testing, and deployment are the final and largest steps in the migration process. Multiple levels of testing of the migrated components and a formal User Acceptance Test will be included. Each of the tasks included in this stage are set out in appropriate section of this document.

3.4 Risk Management

Risk is a natural part of any systems integration project and its proper management can determine its success or failure. Sector7 begins risk management during the proposal process by identifying the foreseen risks in the project and developing an associated Risk Management Plan. This plan identifies and quantifies the risk and Sector7's recommendations.

- Avoidance – eliminating the cause of the risk through clearly-defined actions/events/tasks
- Mitigation – acknowledges that the risk is not avoidable, but defines steps to mitigate the level of risk
- Acceptance – acknowledges an awareness of the risk and documents the associated consequences

New or additional risks are also identified during the progression of the project and are included and managed via the Risk Management Plan. The Sector7 Project Manager utilizes this plan as an instrument to verify our progress against avoidance or mitigation plans with the focus being to reduce the overall risk of the initiative.

There is acknowledged risk in the re-hosting of any application from one platform to another. A strong Risk Management Plan, effectively managed in concert with NFP, will be essential to a successful delivery.

3.5 Quality Assurance

The process that Sector7 utilizes to validate adherence to proper project management processes, our systems integration methodologies, development, and implementation of sound technical architectures is known as Quality Assurance (QA). The objective of QA is the recognition, containment, and/or mitigation of any issues or risks that would jeopardize the success of a project. Success is defined as Sector7's ability to deliver the project to our contractual obligations and to the expectations (satisfaction) of our customer.

We refer to this as assessing the 'project health'. There are two types of QA processes that will be included in our approach – Project Management QA and Technical QA.

The Project Management QA process begins during the development of the proposal under review. Prior to delivery of our proposal, it has already received review from multiple levels of QA to validate that the initial approach is consistent with the proven techniques and methodologies practiced by Sector7.

Shortly after project initiation, Sector7 will perform a QA review to verify that the project is off to a good start, as this is critical to the overall success of the effort. Throughout the life of the project, Sector7 will perform periodic reviews of the project to assess its health and report the findings to Sector7 management. If there are concerns identified then the review frequency is increased until such concerns are alleviated.

It should be noted that client participation is an important aspect of these QA reviews. Sector7 solicits clients' input as part of the process and responds to their concerns, even if they have not surfaced in discussion with the Sector7 team members, or through our review processes. A team comprised of experienced QA representatives, senior project managers, technical staff, and management representatives conduct the QA reviews. The culture of Sector7 welcomes these reviews; we understand their importance and value to the process of delivering quality migration services.

The Technical QA process also begins during the development of our proposal. The proposed solution architecture is reviewed prior to inclusion in our document. At logical milestones in the project life cycle, Sector7 provides an independent technical review of the solution architecture and reconfirms its ability to meet the functional and technical requirements of the project. Senior systems architects and other technical staff, with a focus in the technologies involved, staff the reviews.

3.6 Critical Success Factors

Sector7 has identified the following key-factors believed to be critical to the success of this initiative. Our overall approach and solution addresses these factors as follows:

Strong relationship and open communications

Projects of this nature are successful when both parties are in 'lock step' regarding the project objectives, approach, issues, and ongoing status. The team, which addresses this effort, should be comprised of NFP and Sector7 personnel, which appear seamless. Maintaining open and clear communications at all levels of the project is vitally important.

Proven migration, systems integration, and project management skills coupled with a strong understanding of source and target technology

This project will likely require the choreography of multiple efforts with interdependencies and integration with multiple vendor hardware, software, and networks. Sector7's approach directly addresses this need by providing strong project management and systems integration skills in our service professionals. Sector7 brings a real depth in knowledge of the source architecture, and possesses a proven record of performance in managing similar complex projects with high-customer satisfaction.

Industry knowledge, experience, and leadership

Sector7 has over fifteen years of industry experience, and is well recognized for our leadership in the migration industry. We believe that the combination of our knowledge, skills, and solutions coupled with your subject matter expertise will yield a superior result for NFP.

Training

The migrated applications will utilize technologies and concepts that may appear new to many of the technical staff at NFP. A well-conceived Training Plan that is associated with the proper level of financial investment is imperative for success of the project. Sector7 will work with NFP to assist in defining training needs based on our experience in working with other clients.

Executive Sponsorship

As this initiative crosses many areas of the organization, it becomes increasingly important that there be a consistent level of importance and priority given to the project. NFP senior executives must be in full support of this initiative and provide the appropriate priority of internal resources and financial commitments for the project to succeed.

3.7 Benefits of Re-Hosting

There are numerous benefits of re-hosting, which include:

Business Benefits

- Lower cost of ownership - the escalating costs of hardware maintenance and the associated third-party software maintenance fees will be greatly reduced
- Minimum risk migration with Sector7
- Potential for increase in performance
- Retraining of application users not required
- Opportunity for the current engineering staff to re-skill
- Minimizes system operations training requirements

Technical Benefits

- The application structure will not have changed beyond recognition: development staff will still be familiar with the application code ported to the new platform
- Application logic will remain intact: current staff can support the migrated application

3.8 Teaming

Sector7 believes that fundamental to the success of any client engagement is a desire to establish and maintain a sense of teamwork throughout the project. Teamwork brings the winning combination of skills from both organizations and encourages the necessary level communications, dedication, and synergy to be successful. We welcome the opportunity to work together; it’s our engagement model!

The team of Sector7 and NFP personnel will provide the blend of skills and experience needed for a successful project. Each organization’s strengths, when coordinated as a team on this migration effort, will assure success.

Where possible, it is preferable to perform tasks that do not require Sector7 staff to be ‘face-to-face’ with NFP staff off-site, to minimize expenses and maximize productivity.

Sector7 is sensitive to NFP’s requirements and wishes in all aspects of the project, and are happy to discuss a permanent Sector7 presence on site if NFP feels more comfortable with it. This will of course be subject to agreement on both sides regarding expenses.

4 Scope of Work

This section outlines and quantifies (at a high level) the scope of work to be accomplished by Sector7.

4.1 Key Assumptions

This Budget and Planning Estimate and Sector7's estimates to perform are based on the following key assumptions:

1. This is not a substitute for a formal assessment or proposal by Sector7. This Budget and Planning Estimate focuses on migration tasks and may not necessarily include other tasks that may go into the planning or execution of a migration services engagement. Prices and durations for any future requirements should not be directly extrapolated from this Budget and Planning Estimate, since a variety of other technologies and risk factors may be involved
2. Application information and metrics have been provided to Sector7, and are set out in Table 2 and Table 3. Access to application source code was provided to Sector7 for the purposes of the preparation of this Budget and Planning Estimate – subsequent review of the application source code supplied at the start of the project could impact the Schedule, Charges, or other terms of this Budget and Planning Estimate.
3. Some Sector7 activities on this project will be performed at one or more Sector7 locations, and the remainder at NFP’s location in St. John's, NF Canada
4. All source code delivered to Sector7 must be complete, include no extraneous files and will be "frozen" during the migration project
5. Unless otherwise stated, Sector7 will not be responsible for:
    a. the physical relocation of any hardware components
    b. the sizing/acquisition/installation/configuration/connectivity and management of hardware components including, but not limited to, workstations, servers, storage/backup devices, printers and network components required to fulfill the objectives of this project
    c. the acquisition/installation/configuration/tuning/connectivity and management of foundation software components including, but not limited to, operating system, compilers, administration tools and database software required to fulfill the objectives of this project
    d. the design/planning/acquisition/installation/implementation/tuning and security of the network infrastructure required to fulfill the objectives of this project
    e. the acquisition/installation/configuration/tuning/porting and/or debugging/validation of third-party software components including, but not limited to, development tools, networking, middleware, messaging, and groupware required to fulfill the objectives of this project
    f. the acquisition/installation/configuration/tuning/porting and/or debugging/validation of ‘open source’ components used by the application(s) required to fulfill the objectives of this project
    g. the reverse engineering of software components used by the application for which no source code is available, or for which the source code does not match that of object libraries or executable programs currently used in the production environment
    h. porting development code, which is unstable, untested and unproven. However, we recognize that there may be code that would need to be moved/loaded as-is from development/QA servers to servers in the new consolidated environment. Such code will be moved ‘as-is’ without any effort made to port, test or validate.
    i. functional changes or enhancements to the code being ported beyond the scope of the project; such as 32 to 64-bit conversion
    j. diagnosis and repair of all code defects unrelated to migration changes
6. Sector7 will work with NFP to ensure that the performance of the migrated application, will be equal to or greater than the original performance on the original platform, given that the target platform(s) is/are properly sized, configured and can provide the resources required to meet the performance metrics
7. NFP has expressed interest in sub-contracting parts of this project, specifically the Powerhouse and Axiant elements, to a third party (Core). In this event, Sector7 would retain the lead project management position as this would be essential for overall project control and vision which in turn eliminates a project risk factor
8. NFP will be responsible for performance of the Acceptance Test task of this project and for providing test resources to support the Baseline Testing and System Testing tasks

4.2 Scope

The purpose of this project is to port NFP's CSS application from HP Alpha OpenVMS 7.2.1 to HP HP-UX.

The CSS application and databases are hosted on a single HP Alpha 4100 running OpenVMS 7.2.1. CSS is based on 2-tier architecture with the PC Client and Application/database server.

The online environment consists of a Client/Server GUI architecture built with Cognos' Axiant client/server Integrated Development Environment. Axiant is complemented with some backend calls to Cobol from the online environment.

There is a large batch environment for high volume transactions and larger reporting requests (e.g. post readings, post cash payments, edit accounts, calculate late payment charges, calculate forfeited discount charges, calculate bills, print bills, perform audit checks, populate collection queues, issue form letters, produce daily, weekly and monthly reports etc.)

Powerhouse QTP QUIZ is used on the OpenVMS server for reporting and batch processing with a huge reliance on DCL for the batch architecture. The Nightly batch environment is run by operators.

Data storage consists of Oracle Server enterprise edition version 8.1.6.0.0 plus some native VMS RMS files. RMS files are primarily used to hold interim transactional data, control data and some reporting information and as well to load database tables during batch processing. Powerhouse sub-files are also used.

Integrations are built with Itron's Hand Held Meter reading application and Great Plains e.Enterprise Financials. All integrations are strictly point to point data file transfer.

Development languages and version are:

- Client Desktop:
    - Cognos: Axiant 3.0.
    - Visual Basic module for specific screen handling technique
- OpenVMS Application/Database Server:
    - Cognos' Powerhouse 4GL for VMS Version 820.d3.
    - OpenVMS Cobol 2.4
    - Oracle Pro*COBOL
    - OpenVMS DCL

NFP has provided the following information to Sector7 in April 2003, which forms the basis of Sector7's determinations in this estimate, and should assume to be incorporated into the Key Assumptions.

- The migration target will be HP HP-UX and MicroFous COBOL
- There is no third-party product usage on HP Alpha OpenVMS 7.2.1
- For each test cycle, Sector7's estimate includes 2 Sector7 test resources for 20 days working with NFP testers

Table 2 – Application Information

Development Language	COBOL, Pro*COBOL, Cognos Powerhouse
O/S Dependencies	Some usage of OpenVMS SYS$ and LIB$ system services
Data Storage and Access	Oracle RDBMS version 8.1.6 (2 databases, 30GB total data) Approx 1350 RMS files and 410 Powerhouse Sub-Files
Third-Party Products	Itron Meter reading; Great Plains e.Enterprise Financials
User Interface	Cognos Powerhouse 4GL and Axiant 4GL 3.0 Some character-based VT screens for the batch environment
Networking and Communication	TCP/IP
Middleware	None
Messaging/Groupware	None
Command File Usage	DCL
COTS Usage	None

Table 3 – Application Metrics

Module Type	File Total	Total Lines	Comment Lines	SLOC
COBOL	242	243,146	56,663	186,483
COBOL Copylibs	597	23,532	1,515	21,071
Pro*COBOL	388	700,645	40,578	512,369
Total COBOL	**1,227**	**967,323**	**98,756**	**719,923**
Powerhouse Axiant (.QKP)	167	221,957	118,843	103,114
Powerhouse Axiant (.QKS)	31	3,260	292	2,968
Total Axiant	**198**	**225,217**	**119,135**	**106,082**
Powerhouse QTP (.QTS)	146	9,870	2,025	7,845
Powerhouse QUIZ (.QZS)	659	46,624	7,738	38,886
Powerhouse PDL Source	7	43,554	295	43,259
Total Powerhouse Source	**812**	**100,048**	**10,058**	**89,990**
PVCS Build Files (.BLD)	344	47,807	22,628	25,179
SQL Source	4	8,218	464	7,754
DCL COM Source	1,369	138,112	78,498	59,614

**Note:* Total lines includes comments & blanks*

4.3 NFP's Testing Strategy for CSS

NFP provided Sector7 with the following outline of the existing testing strategy for CSS:

The development environment utilizes a Development/Test/Prod approach. Unit testing is ad-hoc and is performed in the development environment. Functional testing is formal for most changes whereby test plans are created and test data is identified/created usually by extracting live data from the production area and put into the test area.

For almost all of the online functionality and most of the core Batch processes there is a functional specification for each conversation or major batch module. For most of these processes functional test plans are in place, and these are used as templates for development of test conditions for new or changed functionality. Based on the scope of the change, the analyst determines how much of the full test plan to execute for the new functional test.

Integration, regression and performance testing is performed as required. The disaster recovery site is used for these types of testing. To test the batch procedures, system back-ups are recovered to the DR environment (which is an exact copy of production in almost every respect - CPU, database etc. type and size). Specific information is identified for before and after checks as required. Batch processes are ran with timings taken and both broad checks (number of bills, report totals, journal entry totals etc.) and specific checks where identified are completed. Online performance testing is extremely rare for level of change and when performed is done manually in the DR environment. No online testing tools are in place. NFP used *Visual Test* in the last technical migration (COBOL/Install/1 to Axiant/Powerhouse) but because of the nature of Powerhouse it was very manual intensive to set up.

There is no repository of test data or a regression test environment with predefined test data for the overall system. For rate calculation and bill presentation, there is a small regression test environment (called CATS) with predefined test data and refresh and execute procedures. There is a bill checking excel spreadsheet environment which is used to download a sampling of bills each day and check them for accuracy. This is sometimes used to assist testing.

In terms of time it takes to perform the various tests it varies on scope of changes.

The client group is very mature with respect to testing methodology. Traditionally IS performs all testing accept User Acceptance test however NFP has a number of client analysts who perform functional testing now as well. NFP never has the same person performing a functional test and an acceptance test.

Typically because the system is quite stable Integration test, Performance testing and Acceptance testing are completed together however if there are specific performance or integration concerns NFP complete this testing separately or with functional testing.

4.4 Migration Approach

The estimated Schedule and Price is predicated on the following approach to the migration of CSS to HP-UX:

- Build Baseline OpenVMS system at Sector7; rebuild application
- Run tests and verify results
- Build Target HP-UX system at Sector7; install Oracle database and development tools (Oracle, Powerhouse, Axiant)
- Migrate Oracle database from OpenVMS to HP-UX and validate
- Using Sector7 tools, convert VMS COBOL and Pro*COBOL code to MicroFocus COBOL and compile on HP-UX
- Where possible, convert usage of VMS System Services to native HP-UX code. Alternatively, Sector7 may use its VX/RT VMS API library to replace these calls. This determination requires additional analysis. See Appendix B for a description of VX/RT.
- Migrate all Powerhouse code and Axiant screens to HP-UX
- Modify DCL command procedures for Sector7 VX/DCL on HP-UX
- Test / Break / Fix
- Delivery / Handover to NFP
- NFP runs acceptance tests and verify results
- Project completion and sign-off
- Sector7 provides on-site support during installation and client acceptance testing

The above steps are very "high level", but nevertheless show the key components of the project. A staged approach reduces risk and streamlines the migration process, allowing easier testing and more rapid deployment on the new platform.

4.4.1 Benefits of the Proposed Migration Approach

Apart from the general benefits that can be realized through any application migration, such as lower cost of ownership of newer cheaper hardware infrastructure, Sector7's specific migration approach for NFP brings additional benefits:

- Moving the existing CSS from OpenVMS while keeping major technology components reduces project risk by reducing the amount of re-engineering required to make the transition. Reduced risk greatly increases the opportunity for project success and positions CSS on the new platform so that subsequent redevelopment of major technology components can safely take place.
- Retaining the COBOL programming language allows NFP to retain its existing business logic and rules, thereby maintaining the considerable investment NFP has made in this language over the past years.
- Adoption of MicroFocus COBOL gives openness and portability across UNIX and Windows platforms and opens the door for a move to the Microsoft .NET architecture using the MicroFocus NetExpress 4.5 for .NET compiler.
- Retaining the Oracle RDBMS allows the database engine to be deployed on either a Windows or UNIX platform, this decision being dependent on performance factors as well as NFP's corporate choice of platform.
- Retaining the Axiant and Powerhouse elements of the CSS application will enable these components to be moved quickly and easily to the new platform. Axiant and Powerhouse are both extremely portable.
- Retaining the VMS DCL command language enables the DCL elements to be moved quickly and cheaply to either a UNIX or Windows platform, as VX/DCL is available on both.
- To summarize, Sector7's approach in selecting open technologies such as MicroFocus COBOL and Oracle RDBMS will allow NFP to defer the final deployment decision until the port to HP-UX is completed. In this way, the port to HP-UX can be seen as moving CSS onto a "spring board" platform, ready for any future developments and technologies as NFP may choose.

4.4.2 Sector7's VX/Tools suite of Migration Tools

Sector7 is recommending usage of the following elements of its VX/Tools suite of migration tools. Please refer to Appendix B for a full description of these products.

- **VX/DCL** - *VX/DCL* provides a powerful emulation of the VMS DCL environment for both interactive and batch usage in a UNIX or Windows environment. Logical names are supported, mapping to the host file structure. Files and directories may be handled with VMS syntax and with VMS context-sensitive pattern matching, allowing users to continue to work within a familiar programming environment, and may migrate to the new host operating system at their own pace, and through choice, not through necessity.
- **VX/JSP** - *VX/JSP* is an add-on module for *VX/DCL* that provides an implementation of the VMS BATCH & PRINT spooler API and command line interface for UNIX and Windows. With support for over 30 different commands, both batch execution and printer queues are implemented, and function as they would in a VMS environment.
- **VX/RT** - *VX/RT* is a collection of libraries written by *Sector7* that provides the equivalent VMS API functionality on the target UNIX or Windows-NT systems. Over 400 of the most commonly used VMS APIs have been faithfully reproduced with the identical names, arguments, return code and functionality. The *VX/RT* (and other libraries) link into the application to provide the functionality the VMS application requires to perform the application intended task.
- **VX/RMS** - Part of *VX/RT, VX/RMS* is an implementation of Digital's VMS/RMS system for UNIX and Windows. *VX/RMS* allows VMS programs, which access RMS directly, to function without change. All VMS file types and access modes are supported. Support for relative, sequential and block mode files is supplied by direct access to the UNIX/Windows file system.

4.5 Future Re-Engineering Options

Moving CSS to a new platform provides a springboard for future developments and enhancements, examples of which are shown here. These items are not Sector7's recommendations for future technology directions, but merely examples which serve to illustrate some of the options open to NFP for re-engineering CSS once migrated:

- Once the Oracle database is resident on an HP-UX platform, it is simple to add web-enabling technology, such as Oracle Application Server (OAS). Oracle Application Server provides an open, standards-based architecture that is ideal for developing and deploying business and commerce applications for the Web. Its scalable, distributed architecture and superior database integration are the foundation for supporting business-critical, transaction-based applications. OAS might therefore offer NFP a fast track to web-enable the CSS database, with the ability to give users and perhaps customers on-line access through a browser interface. To achieve this, the existing Axiant and COBOL on-line programs could be rewritten/replaced with a mix of Oracle Forms GUI and Java programs creating a 3-tier architecture (database / application / client) where the database and application components could be deployed on UNIX or Microsoft platforms.
- Re-compile all the COBOL code with the MicroFocus NetExpress 4.5 for .NET compiler. This compiles directly to Microsoft's Intermediate Language, and the applications run as managed code within the .NET Common Language Runtime. Developers will have a choice of using Microsoft's Visual Studio .NET IDE to build their COBOL apps or can continue to use Micro Focus' own COBOL development environment.
- Re-engineer the batch COBOL programs as Oracle PL/SQL containerizing them in the database itself and allowing the entire database and batch processes to be deployed on any Oracle supported platform including Microsoft.
- Replace DCL usage with a mix of enterprise products and native HP-UX shell scripts or Windows VBScript/Jscript running under WSH(Note 1). Note that based on past-project experience, the cost of Sector7 re-engineering NFP's existing VMS DCL command procedures "like-for-like" to another scripting language such as UNIX KSH or Microsoft Script would cost around US$250,000, but this is almost certainly the wrong approach. The optimum approach is to undertake a review of how and where DCL is used in CSS at present and to choose strategic replacements for the various elements (e.g. batch processing, batch operations menu, general utility programming language).
- Replace the Sector7 VX/JSP VMS-compatible batch scheduler with a cross-platform enterprise-wide scheduler for streamlined batch processing and unified batch management.
- Option to replace Oracle RDBMS with Microsoft SQL Server, although Sector7 believes that this would be a major re-engineering effort as the existing CSS code is very heavily reliant on embedded SQL (Oracle Pro*COBOL) and SQLServer does not support E/SQL.

Note 1:

Microsoft currently offers three hosts for running scripting language code. They are:

- Internet Explorer (IE)
- Internet Information Server (IIS)
- Windows Script Host (WSH)

The Internet Explorer, and to a slightly lesser extent, the Internet Information Server are well known to developers. However, many developers may not be familiar with the Windows Script Host. WSH is a very useful tool that allows you to directly run VBScript, JScript and XML encoded scripts natively within the operating system.

Windows Script Host comes free with Windows 2000 and 98. Once WSH is installed, it is easy to run a VBScript or JScript program by double-clicking on any file that has the .js or .vbs extension. That file will be executed within the Windows Script Host environment. You can also schedule script execution through the Windows Task Scheduler.

WSH offers a suite of eight objects that can be used for network, registry and shell manipulation. These objects offer greater functionality than that which is available when using either JScript or VBScript alone.

Appendix A About Sector7

Sector7 provides source-code level re-hosting tools and services to organizations in every industry sector, including software, consulting, manufacturing and finance. We offer experience of successfully managing large projects, and a demonstrated ability to manage resources from different organizations. We place great value on our well-defined process, strong project management, technical leadership and emphasis on testing

We have successfully performed many thousands of migration projects for all kinds of companies, all over the world. We specialize in mission critical systems and have migrated many major applications for Fortune 150+ companies. Our toolkits and consulting practice have helped thousands of other companies to migrate their own applications.

For the past 5 years, IBM has chosen Sector7 to be an integral component of their worldwide competitive organization – we provide IBM with sales and marketing support, pre-sales support in the form of our Assessment process, and application migration services. We have performed several thousand application migration projects on behalf of IBM, which makes us a valuable part of their Team.

Utilizing our 5-Step process (refined over the years during many successful re-hosting projects) we are in a position to consider the migration of anything to anywhere, regardless of source and target platforms.

Sector7 was established in the UK in 1985, and since then have migrated many leading-edge applications from one operating platform to another. The experience we've gained is of obvious benefit to new clients: it reduces the time required to migrate and reduces overall cost and risk.

- Offices in North America, Europe and Asia Pacific
- Headquarters and engineering division in the US
- European sales, support and Windows engineering facility in the UK
- Sales office in Asia Pacific
- Provide migration and co-existence tools and services around the world
- Sector7 tools and services provide application developers across all industry sectors with a cost-effective way to migrate existing applications from proprietary systems to other operating systems including, but not limited to, Windows NT and UNIX

Sector7 has clients that span every industry sector, each with their own unique needs, and application requirements.

- Finance
- Banking
- Stock Exchanges
- Global Retail
- Telecommunications
- Manufacturing
- Software
- Consulting
- Chemical
- Aerospace
- Defense
- Government

Sector7 has a multitude of offerings, all built on experience and skill - our core strengths:

- Complete application migration services
- Migration consulting
- Testing and implementation
- Migration toolkits
- Server consolidation using IBM ALIGN methodology
- Application Renovation - Web-enabling, flat file to RDBMS etc.
- 32 to 64-bit porting/empowerment
- PDP-11 RSTS/E, RSX, RT-11 to LINUX/UNIX
- VAX/Alpha VMS/OpenVMS to Windows, LINUX/UNIX, IBM iSeries & zSeries
- UNIX to Windows/LINUXUNIX
- IBM/Amdahl Mainframe to LINUX/UNIX
- HP 3000 MPE to Windows/LINUX/UNIX/IBM iSeries
- RDBMS conversion

A.1 Sector7's 5-Step Process

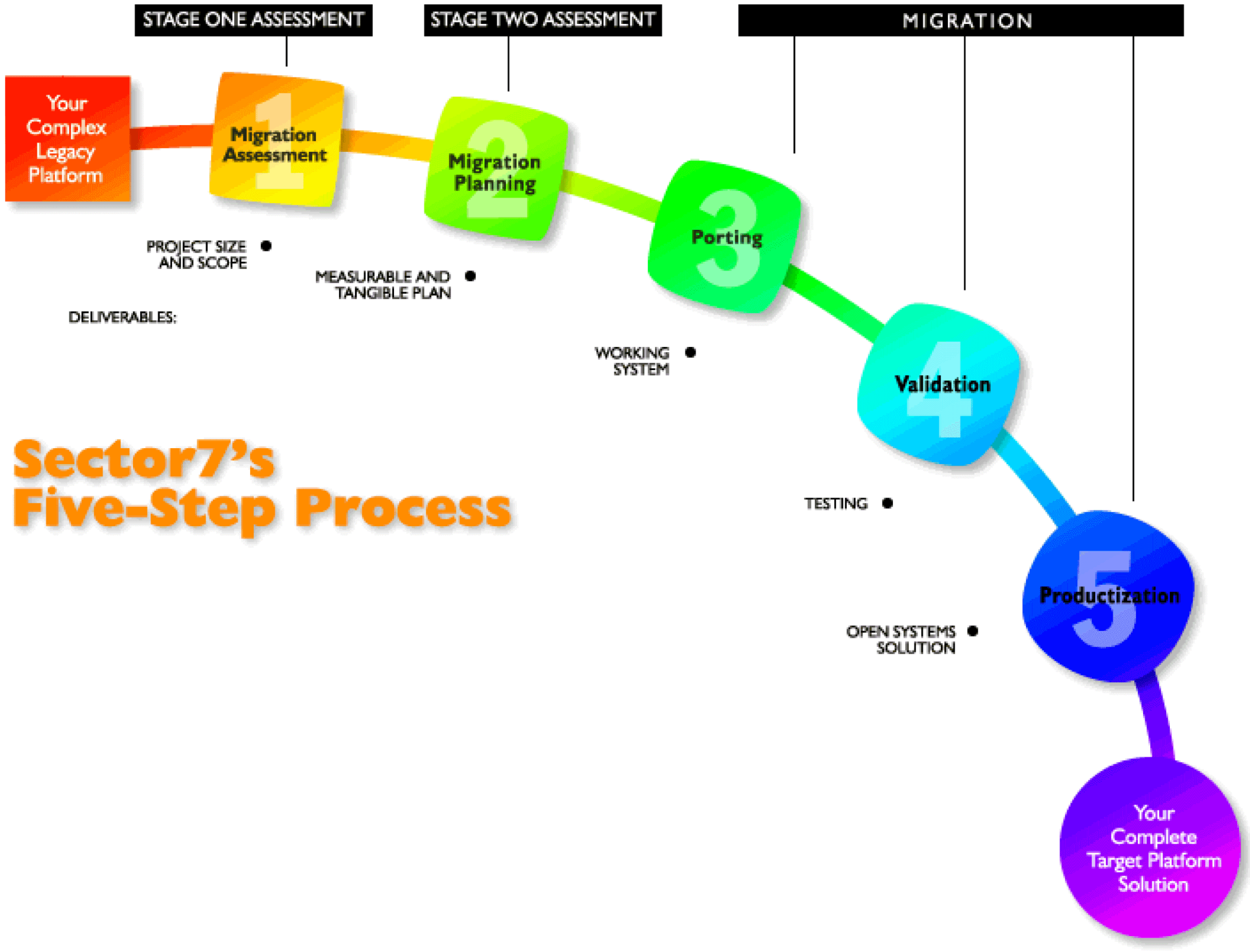
Sector7 uses a proven 5-Step process to ensure successful application re-hosting. These five steps are shown below with the analogous sales/engagement processes. Enhanced and refined over the past 10 years, this 5-Step process forms the basis of all of our project engagements, and allows for "step deliverables" which will provide the Client with information before each stage.

Before embarking on a significant migration project, an organization must be aware of potentially significant challenges in project management and project implementation. Lack of migration experience may cause these challenges only to become apparent in the middle of a migration project.

However, when expected and planned these challenges become opportunities for organizations to learn, grow, and improve. Compatible compilers and porting/migration/emulation tools provide the solution for the obvious technical problems when moving from one operating platform to another. Technical problems, while important, are only part of a business-critical migration project.

To ensure that success, the engagement process consists of the following steps:

- Stage One Assessment (Project Scope)
- Stage Two Assessment (Migration Strategy and Plan)



A.2 Stage One Assessment

The Sector7 Stage One Assessment provides a sound beginning for a successful migration effort.

Process: Migration Assessment – Determine the project scope

Objective: Provide an initial assessment to determine the rough order of magnitude price and duration for a project. Typically, we can provide an estimate to within ±30% of the final price.

Description: The entire environment is reviewed for porting to the desired platform. Sector7 will review the software components such as; language, databases, user interfaces, communications and third party software.

Typical Tasks for Stage One Assessment

- Inventory the code
- Understand application build procedures. The ability to build the application quickly will impact the cost of migration
- Review application source code for porting complexity
- Determine if the existing database is portable to the target platform. If not portable, determine a replacement
- Determine if the existing user interface is portable to the target platform. If not portable, determine a replacement
- Determine if the existing communication protocols are portable to the target platform. If not portable, determine a replacement
- Understand application test and validation procedures, to help determine completion criteria for the project

Deliverables

- Situational Analysis
- Migration Approach
- Overview of Project Tasks
- Budget & Planning Price, usually accurate to ± 30%
- Outline Project Plan
- Application Code Inventory
- *Optionally*, a proposal to perform a Stage Two Assessment

A.3 Stage Two Assessment

The Sector7 Stage Two Assessment provides a sound second step for a successful migration effort.

Process: Migration Planning

Objective: Provide a detailed assessment to determine the maximum price and duration for a re-hosting project.

Description: During the Stage Two Assessment we review any unresolved issues from the Stage One Assessment, and perform a more detailed investigation of the application code.

Typical Tasks for Stage Two Assessment

- Detailed code review for porting complexity
- Develop a plan for database replacement
- Develop a plan for user interface replacement
- Develop a plan for communication protocol replacement.
- Develop a plan for source code control and build procedures
- Develop synchronization criteria
- Develop completion criteria

Deliverables

- Migration specifications
- Detailed migration project plan
- Test plan with completion criteria
- Synchronization plan

A.4 Migration

Process: Porting

Objective: Deliver a working system on the target platform

Description: Perform porting activities defined in migration planning stage

Typical tasks for Migration Stage

- Re-target source language to compile on target platform
- Database replacement
- User interface replacement
- Communication protocol replacement.
- Design and implement new source code control and build procedures
- Acceptance testing
- Assist client with integration activities
- Delivery of a working application

Deliverables

- Working applications on the new target platform in preparation for testing

A.5 Testing

Process: Validation

Objective: Test the ported system on the target platform

Description: Perform all testing activities defined in migration planning stage. This step is tightly integrated with the migration stage as opposed to being a linear task.

Typical tasks for Testing Stage

- Complete regression scripts
- Complete functional testing
- Acceptance testing
- Documentation

Deliverables

- Working applications on the new target platform

A.6 Deployment

Process: Productization

Objective: Deliver a working system on the target platform in a production environment

Description: Perform all deployment activities defined in migration planning stage. This step is tightly integrated with the migration and testing stages as opposed to being a linear task.

Typical tasks for Deployment Stage

- Build applications without internal debugging and use optimization where appropriate
- Configure operating environment for batch processing, user login, and so on.
- Migrate production data from the original platform to the new system
- Cutover to the production system

Deliverables

- Working applications on the new target platform in a production environment

Appendix B Description of VX/Tools

This section is a description of the migration tools that will be used on this project.

One of the greatest value-adds that *Sector7* provides to its customers is a suite of very powerful migration tools. These migration tools will:

- Reduce project cost;
- Mitigate migration risk;
- Automate as much of the migration process;
- And reduce project duration.

Since 1985, *Sector7* has been developing and enhancing a family of conversion tools targeted at significantly reducing the time it takes to migrate an application from OpenVMS to UNIX/Windows. By using our tools, the time, cost and risk associated with a migration or port can be reduced by up-to 90%. Collectively called *VX/Tools*, they fall into 3 groups:

- ➢ Automatically convert the extended VMS source language to its ANSI equivalent (COBOL, BASIC, C, PASCAL).
- ➢ Providing the VMS API (Application Program Interface) to the most commonly used VMS libraries (FMS, SMG$, SYS$, LIB$, MTH$ etc).
- ➢ Providing applications that directly reproduce VMS behavior on UNIX and Windows (DCL, BATCH and PRINT spooling, RTR V2 etc).

B.1 Language Conversion

Sector7 has automatic language conversion tools for VAX BASIC, VAX FORTRAN and VAX C. Details on these tools are omitted from this report as they will not be used.

For VAX COBOL and PASCAL, Sector7 has an “in-house” toolkits which assist in making these language transformations. Details on these tools are omitted from this report as they are Sector7 internal tools.

B.2 System Services Replacement

Product name: VX/RT

VX/RT is a collection of libraries written by *Sector7* that provides the equivalent VMS API functionality on the target UNIX or WindowsNT systems. Over 400 of the most commonly used VMS APIs have been faithfully reproduced with the identical names, arguments, return code and functionality. The *VX/RT* (and other libraries) link into the application to provide the functionality the VMS application requires to perform the application intended task.

Once the VMS specific language extensions and behaviours have been resolved the program can be compiled to object form ready for linking with any external subprograms. Most VMS applications make calls to the VMS operating system to perform system tasks (BAS$, CLI$, CONV$, EDT$, FDL$, FDV$, FOR$, LBR$, LIB$, MTH$, OTS$, SOR$, SMG$, STR$, and SYS$.)

These VMS APIs allow VMS applications to perform complex tasks without the programmer having to write the equivalent functions. It is also these same APIs that cause the greatest difficulty when moving those applications to an operating system that does not support the equivalent APIs.

Sector7 designed *VX/RT* to enable the application to be ported with the minimum number of code changes. To this end, the *VX/RT* APIs accept VMS file specifications and return VMS return codes. For example SYS$OPEN takes a pointer to a FAB and would return RMS$_FNF (98964) if the fine is not found. The FAB requires no changes and most of the fields are supported (obviously some field such as number of extents make no sense on some target systems).

B.3 Filesystem & Database

Product name: VX/RMS

Part of *VX/RT, VX/RMS* is an implementation of Digital's VMS/RMS system for UNIX and Windows. *VX/RMS* allows VMS programs, which access RMS directly, to function without change. All VMS file types and access modes are supported. Support for relative, sequential and block mode files is supplied by direct access to the UNIX/Windows file system.

Features include but are not limited to:

- Support for all RMS file organizations: relative and sequential file types are mapped directly onto the UNIX/Windows file systems. Keyed files are mapped onto an extended version of the industry-standard index file system, C-ISAM
- Fixed and variable length data objects are supported for index and sequential data files. Relative record files support direct access with fixed record lengths
- *VX/RMS* is VMS/RMS call-compatible and uses identical RAB, FAB, XAB and NAM data structure for information exchange between the users, program and *VX/RMS*. All of the fields are compatible, thereby eliminating the need to change application code when porting applications to UNIX/Windows
- VMS file and record locking is fully supported in order to provide the same level of functionality and integrity as VMS/RMS in a multi-user environment. In addition to VMS/RMS record-locking compatibility, *VX/RMS* also retains UNIX/Windows record-locking standards, thereby allowing concurrent access to the data from both migrated and native applications
- *VX/RMS* allows the user to set up and maintain VMS device names and device attributes in a device database. VMS device allocation and de-allocation integrity is maintained allowing shared and exclusive access to specific devices
- *VX/RMS* will recognize I/O to mailboxes, files, and terminal devices
- *VX/RMS* allows optional re-use of deleted record space thereby reducing the need to re-organize index files
- *VX/RMS* supports an optional synchronous data and asynchronous index update mode for fast secure file I/O

Product name: *VX/DataX*

VX/DataX allows users to transport data files from the VMS operating system to UNIX/Windows. *VX/DataX* also allows users to specify a programmable schema to convert the data to the appropriate format (DEC to IEEE, Little Endian to Big Endian, Quadword Data/Time to UNIX/Windows) for the target platform.

B.4 User Tools

Product name: VX/DCL

VX/DCL provides a powerful emulation of the VMS DCL environment for both interactive and batch usage in a UNIX or Windows environment. Logical names are supported, mapping to the host file structure. Files and directories may be handled with VMS syntax and with VMS context-sensitive pattern matching, allowing users to continue to work within a familiar programming environment, and may migrate to the new host operating system at their own pace, and through choice, not through necessity.

Features include, but are not limited to:

- Commands and statements
- Complete batch processing
- Fully integrated lexical functions
- Symbol and logical expressions
- Powerful parser
- Line editing and command history
- User-defined commands
- Interface to *VX/RMS* for file functions (OPEN, READ etc.)
- Print and job spoolers
- SORT/MERGE

Product name: VX/JSP

VX/JSP is an add-on module for *VX/DCL* that provides an implementation of the VMS BATCH & PRINT spooler API and command line interface for UNIX and Windows.

With support for over 30 different commands, both batch execution and printer queues are implemented, and function as they would in a VMS environment.

Features include, but are not limited to:

- Assign/De-assign Queue
- Define Form
- Delete (Characteristic, Entry, Form, Queue)
- Device
- Initialise
- Print
- Set Entry
- Show (Entry, Printer, Queue)
- Start/Stop (Queue, Manager, Entry, Requeue, Reset)
- Submit

VX/JSP is fully integrated with *VX/DCL* to provide a rich set of extended functionality. The job spooler environment includes support for both batch execution and printer queues with the necessary commands to START and STOP the queues, SUBMIT and PRINT.

Product name: EDT+

EDT+ provides a consistent editing interface. Based on the popular EDT editor found on Digital's OpenVMS operating system, EDT+ has been enhanced to include the most requested features of EVE/TPU.

Avoid the expense of retraining, user frustration, and loss of productivity by providing a familiar and powerful tool as users integrate other operating systems into their OpenVMS environment. EDT+ can also be fully integrated with *VX/DCL* to provide a seamless migration path.

Features:

- VAX EDT Gold-Key Editing Plus
- Supports Microsoft Windows editing interface
- Multiple Windows, Status Line, and Other EVE/TPU features
- Powerful User-Defined Keys and Macro Language
- Dynamically Adapts to Current Screen Size
- Supports LINE, KEYPAD, and NOKEYPAD editing modes
- Column Cut and Paste, 4000 Character Line Length
- Enhanced Disaster Recovery
- Easy-to-Use OpenVMS Style Help System

Product name: nu/TPU

nu/TPU is a fully programmable text editor modeled after Digital's TPU (Text Processing Utility). It includes the EVE, EDT and WPS interfaces for easy and familiar text editing across all your platforms, including Windows 2000/NT, Windows 95 and 3.1, DOS, and all major UNIX vendors.

When migrating from OpenVMS to Windows and/or UNIX, it is most beneficial to remain consistent with native application development tools, such as the TPU text editor with its EVE and EDT interfaces. nu/TPU offers full emulation of these interfaces, and is compatible with DEC TPU so that customizations can be ported to a new target system without change. nu/TPU can also be fully integrated with *VX/DCL* to provide a seamless migration path.

- Motif and MS Windows compliant
- Complete TPU programming language
- VMS TPU 5.4 source code compatible
- EVE, EDT, and WPS interfaces
- Supports unlimited files, buffers, and windows
- Fully customizable on the fly
- Column cut/copy/paste operations in insert/overwrite mode
- Horizontal and vertical scroll bars in every window
- Dynamic keyboard definitions
- Unique simple interface (si) shipped with its source code
- Color and other video attributes support
- Unlimited undo
- Command line with abbreviations
- Free and bound cursor movement
- Word wrap
- Wildcard and case-sensitive searches

Appendix C Microsoft SQL Server Data Access

When you choose a development tool and decide how to implement your application, you must also choose the interface by which your application will communicate with SQL Server. The best interface to use depends on the development language and the type of application under development. The choices fall into three categories:

- Call-level interfaces
- Object interfaces
- Embedded SQL

This appendix provides an examination of the interface choices, and is mostly copyright Microsoft Corp.

C.1 Choosing an Appropriate Interface

C.1.1 Call-level Interfaces

A call-level interface offers a set of function calls or APIs that enable client applications to interact with a server database. Call-level interfaces usually use parameters specified as pointers to data input and output buffers owned by the application. Because of this reliance on pointers, call-level interfaces are almost always used from the C/C++ language. With some mapping code, these interfaces can be called from languages that lack pointer support, such as Visual Basic, but usually developers in these languages are more comfortable and productive using an object interface.

SQL Server offers two call-level interfaces:

- Open Database Connectivity (ODBC)—an industry-standard, call-level interface
- DB-Library—the original call-level interface that is specific to SQL Server

At a functional level, ODBC and DB-Library are similar interfaces. They both offer function calls to perform tasks such as opening a connection to SQL Server, executing an SQL statement, and retrieving data from SQL Server. They also have similar performance characteristics. For SQL Server, these two APIs are implemented at the same logical layer in the software architecture; both are "native" interfaces for SQL Server. Both APIs offer full access to the same feature sets, with minor exceptions.

ODBC is the recommended interface and offers the following advantages over DB-Library:

- ODBC is easier to learn

  DB-Library uses different API sets for similar functions that are implemented differently, such as retrieving data using a default result set versus a server cursor. ODBC implements these similar functions using the same APIs and a simple statement option to distinguish a default result set from a server cursor. Because of these special-purpose function calls, DB-Library has many more APIs to learn than ODBC (150 versus 50).

- The ODBC driver uses the performance features of SQL Server automatically

  For example, SQL Server stored procedures can be executed using an efficient procedure call network format. DB-Library uses a separate set of APIs to send requests in the network format. ODBC uses the same APIs used for sending nonstored procedure requests and looks for the standard ODBC "call" syntax to trigger the use of this efficient network format.

- ODBC is an industry-standard interface

  The code and skills used building a SQL Server application on ODBC can be leveraged to build applications for almost any other SQL database. Of course, the code that uses SQL Server features that are not implemented in other ODBC drivers may have to be isolated in a common code base, but this is usually a small portion of the code.

These advantages present a strong case for developing new call-level applications using ODBC. If a company has existing DB-Library applications, there is no need to rewrite them to ODBC unless they are being revised to take advantage of ODBC features. DB-Library applications have excellent performance and will continue to be supported by Microsoft SQL Server for some time. DB-Library, however, will not generally receive feature enhancements in future releases of SQL Server.

C.1.2 Object Interfaces

Object interfaces offer a model of database programming "objects" that can be created by your application and used to send and retrieve data from the database. You can use the objects by calling methods defined for the object and by setting or getting properties on the object.

Object interfaces vary widely in their level of abstraction, exposure of database features, and performance characteristics. They are also usually restricted to specific programming languages. Microsoft offers several object interfaces with overlapping functionality, including OLE DB, ActiveX Data Objects (ADO), Remote Data Objects (RDO), and Data Access Objects (DAO). Other vendors of database programming tools such as PowerBuilder or SQL Windows offer their own object interfaces as part of their tools.

C.1.3 Embedded SQL

Embedded SQL is an ANSI-standard programming interface in which SQL statements, delineated by EXEC SQL tags, are incorporated into the source code of an application. The source code is input to a pre-compiler, which identifies the SQL blocks and replaces them with the appropriate low-level function calls for communicating with the database. An Embedded SQL pre-compiler for SQL Server is currently available for programs written in C in the form of a toolkit that ships on the MSDN™ Library, professional level subscription. This pre-compiler technology has also been licensed to Micro Focus, who offers it as a toolkit for Cobol programmers.

Embedded SQL offers a familiar programming model for developers of applications for other databases such as Oracle or DB2. For Cobol programmers, Embedded SQL is also the most commonly supported database interface of any kind and is an excellent solution for accessing SQL Server. For applications written in C, however, Embedded SQL is somewhat slower than the call-level interfaces and doesn't allow you to take advantage of specific SQL Server features and performance optimizations. The primary design goal for Embedded SQL for C is to follow the strict ANSI standard for maximum portability of applications. Embedded SQL for C is useful if you are porting an application from another database and have a large code base that would be difficult to adapt to ODBC. For these applications, Embedded SQL for C will perform adequately but may not offer optimal performance and control.

C.1.4 Sector7's Conclusion

For optimal performance, Microsoft recommends that Embedded SQL is not used, and instead recommends ODBC for maximum performance. It is further noted that the Microsoft Embedded SQL for “C” and MicroFocus Embedded SQL for COBOL are strictly ANSI compatible and do not therefore allow advantage to be taken of SQLServer's full feature set.

To re-engineer an Embedded SQL application means, in practical terms, stripping out all EXEC SQL statements and replacing them with API calls to the SQLServer ODBC API. As noted above, because of a reliance on pointers, call-level interfaces are almost always used from the C/C++ language. With some mapping code, these interfaces can be called from other languages.

The cost of this re-engineering is proportionate to the number of embedded SQL statements contained in the original source language, plus additional costs for the analysis and re-design of the data access methodology considering different database manufacturer's implementations of locking etc.

Appendix D Testing Guidelines

The definition and creation of a viable test plan is critical to the success of a migration project. Used during various stages of the project, test plans serve to validate the base-line system, assist the developers in performing unit and system tests, and provide the framework for final acceptance testing.

Specific test plan details vary from project to project, however Sector7 employs the same overall approach with the same basic requirements for all project test plans. This document describes test plan creation and usage at Sector7.

D.1 Overview

Generally speaking, the more time spent up front putting together a detailed test plan, the greater the chances for success in meeting project deliverables, schedules and expectations. Like many other similar exercises however, the law of diminishing returns comes into play at some point in time.

The danger lies in developing a plan with procedures so complex or comprehensive that it becomes impractical or too time-consuming to execute efficiently. The challenge then, is to define a test plan sufficiently detailed to ensure application integrity and validity; yet simple enough to allow efficient and repeatable execution.

It is, of course, important to consider that the time required to run the tests is dependent upon the speed of the platform on which the testing is being performed.

D.2 Subject Matter Experts

Subject Matter Experts, individuals thoroughly familiar with the application and all of its operational details, must ultimately construct test plans. The individual tests should be documented in sufficient detail such that testers not necessarily familiar with the application can efficiently execute them.

In some cases, comprehensive automated test suites exist and can be employed effectively for validation of migration projects. In cases where they do not exist, we recommend the use of manual procedures, scripted out in step-by-step detail. Undertaking the development and implementation of an automated test procedure can be an involved and significant task.

We realize that creating a test plan can be a resource intensive and time-consuming task. To help alleviate these problems, Sector7 has experienced test managers available to work directly with clients in developing test plans tailored to their specific environment and project requirements. The rest of this appendix will describe the manner in which Sector7 projects utilize test plans as well as the steps we recommend for test plan creation:

D.3 Test Plan Usage

D.3.1 Baseline Validation

The “baseline” system forms the agreed-upon starting point for a migration project. The overall objectives of baseline validation include verification of the fact that source code received from the client can be built and validated on the source platform at *Sector7*. This assures we are migrating the correct version of the code, and that we have all necessary source modules.

Successful execution of the test plan validates the system and forms the reference point for functionality comparisons. Successful test plans include mechanisms for capturing and saving output in the form of screen-prints or hard-copy reports.

D.3.2 Unit Testing

During the development and debugging stages, programmers need to be able to run parts of the application to recreate and track down problems. Although programmers may not execute entire scripts each time they wish to test, the tests should be sufficiently well documented such that basic program functionality can be inferred. Naturally, this assumes the client provides SMEs (Subject Matter Experts) to train *Sector7* personnel on application details and interpreting test results.

D.3.3 System Testing

After all modules are migrated and successfully unit tested the project enters the system test phase. During this phase the target environment is created, data is migrated or converted and the code moved to an isolated test system.

Installation and configuration procedures are devised and tested, and trial deployments performed to identify and document setup procedures, necessary hardware and software components along with the required revision levels. After the target environment is stabilized the test plan is used to perform system tests and ensure the migrated application functionality is complete and correct.

When allocating time for system testing, we normally allow triple the time it takes to perform the baseline test (e.g. if the baseline takes 60 hours to run end-to-end, then we allow 180 hours for system testing).

D.3.4 Acceptance Testing

Acceptance testing performed by the client at project completion validates the results of the entire migration project. It forms the basic agreement by both parties that the migrated code on the target platform is functionally equivalent to the code on the original source platform. It is imperative the plan be agreed upon by both parties prior to this task to ensure successful project conclusion.

In terms of project deliverables and risk management, this task represents the most critical utilization of the test plan. Care must be taken therefore, to ensure the plan specifically address application “hot spots” (i.e. heavy usage/traffic) as well as functional areas devoted to supporting “mission critical” business processes. Interfaces to external systems almost always present high exposure, so test plans usually stipulate individual detailed tests for each interface.

The final acceptance test generally takes the same amount of time as the baseline. The assumption is that once all the system testing is done, we then run through the baseline/acceptance from end to end on the basis that it will be clean and ready to pass over to the client.

D.4 Test Plan Creation

D.4.1 Defining the Testing Approach

The first step in creating a test plan is to define the testing approach. This need not be a complex or detailed process; it is often sufficient to simply indicate how different application areas will be tested. For example: on-lines will be tested by operators manually entering data from scripts, batch jobs will be submitted and reports saved, etc.

Besides specifying how the tests will be performed, consideration must be given to the logistics necessary to make the tests repeatable (e.g. restoring data to known state before each test run, etc.). In addition, the manner in which results will be captured, saved and compared to the baseline validation system should be carefully defined and documented.

Perhaps most critical to the beginning of testing is the definition of what activities and results constitute completion of the project. These activities are known collectively as *“Acceptance Criteria.”* These acceptance criteria, included as part of the test plan, include a list of specific tests where the migrated code results will be compared with the results generated from testing the original code. The completion of testing and the comparison, or resolution of discrepancies encountered, is used to indicate completion of the project. The customer and *Sector7* are required to approve the specific conditions for acceptance testing.

D.4.2 Defining the Application Subset to Test

After deciding upon an overall test methodology, the next step defines a subset of the application to test. Obviously, it is not practical to attempt to validate every possible code path in a large complex application. Our experience shows that testing 70-80% of the modules is generally sufficient to validate the migration, depending on application flexibility and complexity.

There are several reasons for this:

- Analysis and profiling reveals the vast majority of application utilization is generally performed using a subset of the full application functionality.
- Profiling also reveals that even within highly utilized application functions, specific code paths are executed much more frequently than others.

- Applications are usually constructed with subroutines or library calls performing complex or common application functions. When these routines are indirectly tested within one functional test, there is usually no need to validate them from other functional tests as well.
- Migration projects are unique in the sense that they do not introduce new functionality into the application. The same overall approach is usually taken in migrating all modules (i.e. automated tools, procedures, etc.). This generally means that corrections to migration-related defects resolve all instances of the problem.

These reasons combined with the fact that test plans must be complete and detailed, yet simple enough to execute efficiently, support the approach of defining an application subset for testing. The difficulty lies with choosing the appropriate modules for inclusion in the plan. *Sector7* recommends that QA personnel developing the test plan consult application SMEs as well as technical architects to ensure the proposed plan includes sufficient coverage.

D.4.3 Defining Tests for External System Interfaces

Sector7 recommends the application subset approach not be taken for testing external system interfaces. These components normally represent high risk factors and are sufficiently different enough from each other to warrant individual test plans. This argument is reinforced by the fact that SMEs for the external systems are not usually available, and sometimes the tests must be performed by, or requires extensive support from, technicians.

D.5 Training Sector7 on Test Procedures and Interpreting Results

Throughout the migration project, engineers and testers perform partial or complete test procedures for unit and system testing. Furthermore, it is often necessary during problem analysis and troubleshooting, to run application tests under the debugger for investigation and resolution.

It is therefore necessary for client testers or SMEs to provide training for *Sector7* migration engineers and testers to enable them to run the tests independently and verify the correctness and completeness of observed results.

D.5.1 Define Test Results Approval Process

It is extremely important to specify the exact method by which test results will be captured, reported and approved. Forms or other control vehicles should be defined and created, sufficiently general enough to cover all types of individual test results. Other factors covered in this task include designating which individuals are responsible for approval, mechanics for communication and follow-up and establishment of turn-around time frame expectations.

D.5.2 Script Each Functional Test

Sector7 recommends that client QA personnel or SMEs actually produce written scripts for each functional test. These detailed documents list each prompt the tester sees when performing a test and indicate the data entry keystrokes necessary to advance to the next step within the test. Screen prints are not necessary, although they do help in quickly identifying format problems. The scripts also list expected results or output generated in response to keystrokes or actions taken by the tester.

The client needs to allocate sufficient time for this activity, as development of test scripts is not a trivial task. Similar to programs, all but the simplest of scripts must be executed multiple times and debugged by the author to ensure they accurately reflect the actual application dialog with the user.

D.5.3 Approval and Agreement by All Parties

The final step in defining a test plan is to obtain approval and agreement from all involved parties that the plan is viable and complete enough to fulfill the needs described above.

Appendix E Application Code Inventory

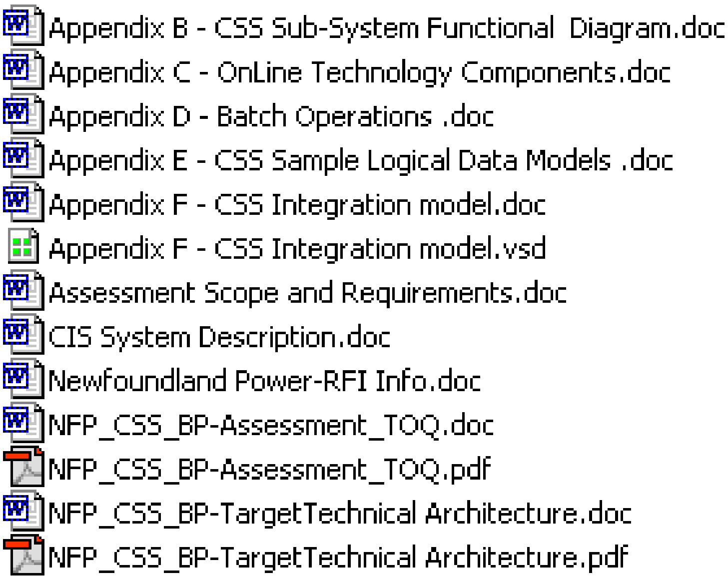
The accompanying Adobe PDF file '*NFP_CSS_BP-Inventory_v1.3.pdf*' contains an inventory of the application source code that was delivered to *Sector7* in April; 2003 for analysis. The analysis, content, assumptions and determinations of this document are based on this inventory.

Appendix F Technical Analysis Questionnaire

The accompanying Adobe PDF file contains the original Technical Overview Questionnaire submitted to Sector7 by NFP.

NFP_CSS_BP-Assessment_TOQ.pdf

The following documentation was also provided by NFP:



Appendix B - CSS Sub-System Functional Diagram.doc
Appendix C - OnLine Technology Components.doc
Appendix D - Batch Operations .doc
Appendix E - CSS Sample Logical Data Models .doc
Appendix F - CSS Integration model.doc
Appendix F - CSS Integration model.vsd
Assessment Scope and Requirements.doc
CIS System Description.doc
Newfoundland Power-RFI Info.doc
NFP_CSS_BP-Assessment_TOQ.doc
NFP_CSS_BP-Assessment_TOQ.pdf
NFP_CSS_BP-TargetTechnical Architecture.doc
NFP_CSS_BP-TargetTechnical Architecture.pdf

The analysis, content, assumptions and determinations of the Budget and Planning Estimate are in part be based on the information provided in this documentation.

End of Document

Appendix S - CSS Technical Migration Alternatives Internal

Customer Services System

Technical Migration Analysis

May 2003

1. Introduction

The objective of this document is to detail the alternatives for the technical migration of Newfoundland Power's Customer Service Application (CSS) from an OpenVMS platform to a Windows and/or Unix platform. The OpenVMS platform and the Powerhouse 4GL application development environment is no longer part of the Company's long-term target architecture strategy.

Two basic alternatives with respect to the application development language is being explored:

OpenVMS re-platform while keeping major technology components (e.g. Powerhouse, Axiant etc.).
OpenVMS re-platform but redeveloping the major application development technology components according to the Company's Target Technology Architecture (eliminate reliance on Cognos Axiant and Powerhouse proprietary software).

Information to validate these alternatives were gathered through discussions with our existing Technology Partners: Microsoft, Hewlett Packard and Cognos. IT industry (Non vendor biased) information was retrieved from discussions with leading analysts from Gartner and Meta Group IT analysts. Several relevant vendors specializing in migration services were contacted and provided initial assessments
OpenVMS migrators; Sector7 and HP
Powerhouse retooling vendor; CORE
Powerhouse porting vendors: Intertech and Inbusiness solutions

2. Technical Migration Alternatives

For the purposes of this document these are the five technical migration alternatives with respect to the Company's future target architecture that are deemed to be acceptable with respect to the level of effort and overall risk to the company at this time. For the purposes of this document:

the term **re-platform** refers to a move to another operating system environment,
retooling refers to changing the underlying application development code, and
DBMS conversion refers to a migration from Oracle to MS Sql Server relational DBMS product.

Regardless of the alternative migration path, improvements to the batch architecture by the purchase and implementation of automated batch submission control software and improvement to CSS reporting environment are considered in scope, and are in addition to the estimated costs of the alternative outlined below.

OpenVMS Replatform : ***UNIX***
(Online:Windows Batch/DBMS: UNIX retain Powerhouse Axiant/QTP/QUIZ, Oracle DBMS)

OpenVMS Replatform : ***WINDOWS***
(Online/Batch/DBMS retain Powerhouse Axiant/QTP/QUIZ, Oracle DBMS)

OpenVMS Replatform/AD retooling ***WINDOWS***
Online/Batch/DBMS migrate off Powerhouse Axiant/QTP/QUIZ, Oracle DBMS

OpenVMS Replatform/AD Retooling ***WINDOWS/UNIX***
Online: Windows Batch/DBMS: UNIX migrate off from Powerhouse Axiant/QTP/QUIZ, Oracle DBMS

#5 **OpenVMS Replatform/AD Retooling/DBMS Conversion** **WINDOWS** Migrate off of Powerhouse Axiant, Database conversion MS SQL Server DBMS

The strengths and weaknesses associated with each of these alternatives are explored in more detail.

2.1 #1 OpenVMS Re-platform – UNIX

Description:

Migrate off of the OpenVMS platform but keep all major applications development components (Axiant, Powerhouse and COBOL). Maintain Oracle DBMS but migrate to UNIX platform. This would involve:

CSS Online to UNIX
- Axiant migrates to Axiant on UNIX server. (Alternative would be Axiant on Windows via a thick client/server deploy because Axiant is not supported via CITRIX). While it is true Axiant is not supported on Citrix it would not have to be a thick client. Powerhouse on Windows supports a thin client install where the application logic sits on the Windows server just as it does today on the OpenVMS server and only the presentation layer is on the clients desktop.
- Online COBOL back-ends convert to Microfocus COBOL

Batch to Unix
- Batch COBOL migrates to Microfocus Cobol on Unix.
- Batch Powerhouse QTP and QUIZ migrates to UNIX.
- DCL converts to Unix shell script (or utilize DCL emulating software which is not our preferred method).

Strengths:
- Overall the least amount of technical effort and risk as compared to all other options. There are many translation/emulation software products on the market (Sector7 and Accelr8).
- Overall the least risk with respect to availability and scalability issues as compared to options 2, 3 and 5 because of similarities between OpenVMS and UNIX platforms (95% of OpenVMS migrations are to the UNIX operating system).
- Least amount of new investment in hardware required for production, disaster recover, and development environments because some of the existing OpenVMS hardware could be reused.
- This would be a starting point for a phased migration effort.
- This is the least inexpensive migration path for Newfoundland Power of all other options.

Weaknesses:
- Niche AD toolset (COGNOS Powerhouse 4GL/AXIANT)
- Concerns regarding future of application development tools from COGNOS whose key revenue stream and R&D is in the BI reporting suite.
- Skill set shortage and lack of local training
- UNIX is not part of Newfoundland Power targeted architecture moving forward.
- Limited internal skill set with respect to UNIX environment

This alternative is supported by experienced leading IT industry migration vendors who specialize in technical migration efforts. Sector7 stated that, based on their experience, the UNIX platform would be the least risk and keeping Powerhouse AD tools would be the least cost alternative for Newfoundland Power.

Cost estimation: $2,000,000 to $3,000,000
Intertech $500,000/ HP $800,000/ Sector7 $1,250,000 ~300 day or 1 year duration
Sector7 Tools/Software $100,000
Hardware/OS $500,000
Internal Labour $750,000

Effort: 12 Months

2.2 #2 OpenVMS Re-platform – Windows

Description:
Migrate off of the OpenVMS platform but keep all major applications development components (Axiant, Powerhouse and COBOL). Maintain Oracle DBMS but migrate to Windows platform. This would involve:

CSS Online to Windows
- Axiant migrates to Axiant on Windows server.
- Online COBOL back-ends convert to Microfocus COBOL

CSS Batch to Windows
- Batch COBOL migrates to Microfocus Cobol on Windows.
- Batch Powerhouse QTP and QUIZ migrates to Windows.
- DCL converts to Windows (.BAT / .CMD)

Strengths
- Get some native windows GUI improvements from AXIANT on Windows (navigation, integration to EXCEL, Outlook, VB scripts)
- Least impact on end user from a change perspective
- Least impact on end user resources during migration
- Overall the least amount of technical effort (coding and testing)
- Ease of testing (limited to batch environment)
- Most inexpensive migration path to get off of OpenVMS
- Axiant license transfer to Windows
- Cost of Powerhouse (QTP/QUIZ) for Windows
- Move code and compile for windows environment.

Weaknesses

- Niche AD toolset
  - Concerns regarding future of application development tools from COGNOS whose key revenue stream and R&D is in the BI reporting suite.
  - The install base for Powerhouse on Windows platform is very low. This would be a concern for overall support (patches, upgrades) and future de-support (See Appendix A)
  - Skill set shortage and lack of local training
- Extensive programming effort required to convert Batch architecture to Windows (1500 DCL procedures with 150,000 lines of code converted to Windows .BAT or .CMD code).
- Overall the greatest risk with respect to availability and scalability based on the current architecture of CSS. CSS was designed for the mainframe (mini) computing platform, OpenVMS, which is a 64 bit, multi-user platform. Windows recently released its first 64bit operating system Windows 2003 (May, 2003) and therefore is still immature.
- The Windows operating system is not a true multi-user system. CSS would have to be deployed via thick client/server and/or terminal services. Thick client/server would experience bandwidth issues for area offices running CSS. Terminal services would require ‘server farms’

and load balancing and therefore there would be extensive costs for hardware and resources. This was supported by SECTOR7 .

- Extensive new investment in new hardware required for production, disaster recovery, and development environments

Cost estimation: $2,500,000 to $3,500,000

HP	$800,000
Tools/Software	$150,000
Hardware/OS	$750,000
Internal Labour	$1,250,000

Effort: 12 - 18 Months

2.3 #3 OpenVMS Re-platform – Windows; AD Language Retooling

Description:

Migrate off of OpenVMS. There will be a technical migration of Axiant, Powerhouse and COBOL Application Development Components while maintaining the Oracle DBMS but with migration to another platform. This would involve:

Online to Windows
- Axiant converts to MS .NET ASP/VB.
- Online COBOL back-ends convert to Microfocus COBOL

Batch to Windows
- Batch COBOL converts to Microfocus COBOL
- Batch Powerhouse QTP and QUIZ (all non-reporting versions) migrates to PL/SQL within the Oracle DBMS complement with Impromptu for reporting purposes
- DCL converts to Windows (.BAT / .CMD)

Strengths
- Market leading AD toolset (eliminates reliance on niche Cognos AD toolset) with growing local skill set expertise
- Improved data integration with MS Suite (Outlook, Excel).

Weaknesses
- Currently only one vendor offering automating code conversion tools for Powerhouse to MS ASP conversion (CORE Software Ottawa)
- Migrating from the AD toolset (AXIANT) would constitute a substantial change to the CSS architecture, as well as the user interface and would require a substantial overall effort of a technical migration project requiring comprehensive testing.
- Overall technical effort is substantial.
- MS .NET technology is still rather immature (bleeding edge technology) and the adoption rates are still rather slow.

Cost estimation: $4,500,000 to $6,000,000

Core	2,250,000
Software	$100,000
Hardware/OS	$750,000
Internal Labour	$1,500,000
COBOL/DCL/DBMS	$1,000,000+

Effort: 18 - 24 Months

2.4 #4 OpenVMS Re-platform –Windows/UNIX; AD Language Retooling

Description:

Migrate off OpenVMS. There will be a technical migration of Axiant, Powerhouse and COBOL Application Development Components maintaining Oracle DBMS but with migration to another platform. This would involve:

Online to Windows

- Axiant converts to MS .NET ASP/VB.
- Online COBOL back-ends convert to Microfocus COBOL

Batch to Unix

- Batch Powerhouse QTP and QUIZ (all non-reporting versions) migrates to PL/SQL within the Oracle DBMS were possible otherwise to Impromptu.

Strengths

- Market leading AD toolset (eliminates reliance on niche Cognos AD toolset) with growing local skill set expertise
- Improved data integration with MS suite (Outlook, Excel).
- Utilizing UNIX platform for DBMS and batch processing would be prudent from a staging perspective and help mitigate risk with availability and scalability issues with a windows environment as identified in option 3.

Weaknesses

- Currently only one vendor offering automating code conversion tools for Powerhouse to MS ASP conversion (CORE Software Ottawa)
- Migrating from the AD toolset (AXIANT) would constitute a substantial change to the CSS architecture and as well as the user interface and would require a substantial overall effort to a technical migration project requiring comprehensive testing.
- MS .NET technology is still rather immature (bleeding edge technology) and the adoption rates are still rather slow.

Cost estimation: $4,000,000 to $5,000,000

Core	2,250,000
Software	$100,000
Hardware/OS	$500,000
Internal Labour	$1,250,000

Effort: 15 - 24 Months

2.5 #5 OpenVMS Re-platform – Windows; AD Language Retooling; DBMS Conversion

Description:

A re-platform off of OpenVMS, technical migration of Axiant, Powerhouse 4GL with a database conversion to MS Sql Server. This would involve:

Online Windows

- Axiant converts to MS .NET ASP/VB.
- Online COBOL back-ends convert to Microfocus COBOL

Batch to Windows

- Batch Powerhouse QTP and QUIZ (all non-reporting versions) migrates to Trans-SQL within the MS Sql Server DBMS.
- DCL converts to Windows (.BAT / .CMD)

DBMS Conversion

- Migration of all existing Oracle stored procedures and triggers to MS SQL Server Trans-SQL procedures
- Removal of all embedded SQL in COBOL code to SQL Server API ODBC call interfaces
- Procedural code to perform data extraction from Oracle and loading of MS SQL Server
- Extensive testing for data integrity purposes and performance related testing

Strengths

- Market leading AD toolset (eliminates reliance on niche Cognos AD toolset) with growing local skill set expertise
- Improved data integration with MS Suite (Outlook, Excel).

Weaknesses

- Currently only one vendor offering automating code conversion tools for Powerhouse to MS ASP conversion (CORE Software Ottawa)
- Migrating from the AD toolset (AXIANT) would constitute a substantial change to the CSS architecture, as well as the user interface and would require a substantial overall effort of a technical migration project requiring comprehensive testing.
- Overall technical effort is substantial.
- MS .NET technology is still rather immature (bleeding edge technology) and the adoption rates are still rather slow.
- To convert the Oracle DBMS to MS Sql Server this involves extensive technical data conversion/testing effort.
- Technical differences in ANSI SQL from Oracle and MS Sql Server standard SQL (doesn't perform with COBOL imbedded SQL)
- Extensive level of stress testing required to ensure overall performance and locking is at acceptable level.

- Increased level of functional testing required to ensure data integrity associated with data conversion, locking strategy, concurrency model and coding changes
- The DBMS would no longer be open from the perspective of OS independent.
- MS Sql Server is not as robust as Oracle from the perspective of performance, reliability, scalability and security.
- SQL Server has no multi-version consistency model, which means that "writers block readers and readers block writers" to ensure data integrity therefore locking issues would be highly likely

Cost estimation: $5,000,000 to $7,000,000
Core 2,250,000
Software $100,000
Hardware/OS $750,000
Internal Labour $1,750,000
COBOL/DCL/DBMS $1,500,000+

Duration: 18 - 24 Months

3. Recommendation

Given the estimated cost and effort and the present overall IT industry concern with respect to the Windows environment to support an enterprise class application, the maturity of .NET and 64-bit architecture and the need to extensively re-architect CSS for this environment it would be wise to phase in the technical re-platforming and retooling migration of CSS. This can be achieved by implementing these changes in several phases over a 2 to 3 year time period;

Phase 1: re-platforming while retaining the COGNOS AD toolset to a UNIX platform as in depicted option 1

Phase 2: re-tool the online AD technical component by migrating the online portion of CSS to the MS tool set while retaining the batch component on UNIX as depicted in option 4.

Phase 3: re-tool the batch technical component of CSS to the Windows platform by utilizing stored procedures and automated batch software with the end result being option #3.

Appendix A – Cognos Response

Newfoundland Power Answers April 3, 2003

Cognos future direction

- Axiant – Road map
    - Platforms (OpenVMS, Windows, Unix)
    - Products
    - Support
- Powerhouse – Road map
    - Platforms (OpenVMS, Windows, Unix)
    - Products
    - Support

We are just about to release (April or May) a major new product suite, PowerHouse 8.4, Axiant 3.4 and PowerHouse Web 2.4. Along with a major conformance update and other new features , we have introduced DB2 for UNIX and Windows, and DISAM for Windows, to our suite of supported file systems. As well, QUICK will now be available on Windows, making the PowerHouse product a full development product on Windows, just like it is on other platforms. The current suite of products, being readied for release, involved a very major conformance upgrade that brought us in line with the same data access layer that is used by the Series 7 products.

In a release that will come a few months after this major product suite release, we will also feature support for Eloquence on HPUX and Windows.

Our current largest base is the Hpe3000. With the announced demise of this platform, our customers are now making plans to protect their investment by moving to another Cognos supported platform. This is a key objective for us, our VARS and our Partners. Many customers are still evaluating this requirement.

Roadmap: Our plan going forward is to put out a new base release about once a year or year and a half, with maintenance releases in between. Our focus will be customer driven enhancements and database and operating system conformance.

Note:

VAX: PH830 was last release.
Tru64: PH840 will be last release.

- How strong are the commitments?
    - Guarantees in writing Axiant and Powerhouse (OpenVMS)
    - Guarantees in writing Axiant and Powerhouse (Windows/Unix)

ADT tools are most certainly still a significant contributor to our company's bottom line. As such, we will continue to plan and execute product release strategies as long as there is customer demand and business viability. We do not have any end of life timelines other than for Hpe3000. In the case of the Hpe3000, HP has announced that they will support that platform until 2006. We will follow their support timeline here.

New sales Application Development (Axiant / Powerhouse) statistics:

Significant sales, types of customers buying, Operating System Install Base/Trend. Supported by trending information to illustrate renewed interest or re-entrenchment into Powerhouse and/or Axiant.

We do not do detailed market analysis on the ADT customers as to their line of business, but we do know that our VARS develop all sorts of applications: inventory, hospital, manufacturing, etc.

Are third-party software vendors developing systems in Powerhouse/Axiant?

Yes, Marianne can give some very good examples.
Stargarden Software – develop an HR/Payroll application
Cyframe International – develop a Health Care application
Vantagepoint – develop an ERP application for Pulp & Paper Industry
Infotech – develop a Customer Care application
I have only listed a few that I know have developed packages with Axiant. Our Website should list our partners that have developed both Axiant and PowerHouse applications.

4. Migration

Cognos Platform migration services:

Type of services available from Cognos in this area

Powerhouse Quiz/QTP & Axiant from OpenVMS to Windows/Unix
Powerhouse Quiz/QTP to Impromtu/Powerplay

As Marianne indicated, Cognos will do application reviews, however we do not do migration services. Cognos has developed a Migration Course (called Migrating Applications with Axiant 4GL). This course shows how to use Axiant to migrate your PowerHouse 4GL from one environment to another and from indexed file systems to relational. We do however have partners who do this type of work. As discussed, Newfoundland Power has been in touch with several of our partners already.

Recommended Migration Partners:

Powerhouse Quiz/QTP & Axiant from OpenVMS to Windows/Unix
Powerhouse Quiz/QTP to Impromtu/Powerplay

As discussed, plus we list most of them on our web page http://powerhouse.cognos.com)

Installed Base

We have approximately 2900 supported PowerHouse, PowerHouse Web and Axiant customers worldwide. These customers run the gamut from small shops with one or two licenses, to very large installations with 1000 or more concurrent PowerHouse users.

The order of installed base from high to low, is as follows:
HPe3000
VMS Alpha
HPUX
VMS VAX
IBM AS400
RS6000 (AIX)
NT
Solaris
Tru64

Appendix T – Summary of Bolt-on Vendor Responses External

Customer Service and Support Applications RFI

Summary of Vendor Responses

March 2003

xwave
AN ALIANT COMPANY

TABLE OF CONTENTS

1 INTRODUCTION

1.1 Background

Newfoundland Power's current Customer Service System (CSS) is a legacy application which has been in production for over 10 years. The company is currently examining several options with regards to the future of the CSS; rather than pursuing a full system replacement – which has major cost implications - the company is investigating possibilities for extending the life of the CSS. Newfoundland Power's desired approach to achieving this is, where appropriate and economical, to identify and implement commercial applications which can be interfaced with, or "bolted" to, the current CSS system.

Enhancements/changes to the CSS are required for two main reasons:

1. There are some types of functionality which are either not delivered at all by the current CSS or which have the potential to be delivered more efficiently and/or effectively. Newfoundland Power may be interested in integrating suitable commercial applications with the current CSS, if such applications can be identified.

2. The current CSS application is running on an OpenVMS operating system. OpenVMS is not the platform of choice for future corporate applications and, as a result, Newfoundland Power is evaluating the merits of re-platforming its CSS. If the company chooses to re-platform, certain pieces of CSS functionality may be purchased rather than re-coded in-house.

1.2 Purpose of RFI

Newfoundland Power asked **xwave** to conduct research on CSS vendors in the marketplace who might be considered when looking for bolt-ons to the CSS. **xwave** found a significant amount of information was available on Customer Information System (CIS) package vendors. This information was examined to discover that the information available did not indicate whether vendors' solutions could be broken up and sold by specific functional area. Given that Newfoundland Power is not interested in purchasing and implementing a full CIS application, the ability of vendors to sell products in a modular fashion was essential information. In addition, most of the information available profiled large CIS package vendors but left out smaller, niche vendors which Newfoundland Power was interested in learning about.

xwave recommended issuing a Request for Information (RFI) to appropriate vendors to uncover the desired information. On February 28, 2003, **xwave** issued an RFI for Customer Service and Support Applications on behalf of Newfoundland Power.

1.3 RFI Methodology

1.3.1 Development of RFI Document

In conjunction with Newfoundland Power, an RFI document was developed. Among other things, the document included the following information about Newfoundland power and its Customer Service System:

- Functionality provided by Newfoundland Power's current Customer Service System;
- Functionality of interest to Newfoundland Power for the future of its CSS;
- Technical architecture of the current CSS;
- Target architecture for any CSS enhancements; and,
- Overview of Newfoundland Power's technical environment.

The RFI also provided instructions to vendors with respect to information required in RFI responses.

1.3.2 Identification of Vendors

The next phase of the RFI process was to develop a list of vendors who should receive the RFI. A preliminary list of vendors was compiled using the following sources:

- Skipping Stone Fall 2002 CIS/CRM Software Report
- Warren B. Causey 2002 Energy/Utility CIS/CRM Report
- TMG Consulting Presentation to Newfoundland Power (Fall 2002)
- List of CIS Providers on CISWorld[1] web site (http://www.cisworld.com)
- List of exhibitors from 2002 CIS Conference

With assistance from Newfoundland Power, this list was refined. Any vendors who stated clearly that their products were "package only" applications were removed. Vendors who focus on CIS for non-electric utilities (e.g. water utilities) were removed. Finally, some vendors/products were already known by Newfoundland Power and were not of interest and were also ruled out.

Once the initial list was refined, Newfoundland Power provided names of a number of niche vendors who were not referenced by any of the original sources used. These niche vendors fell mostly into the functional areas of Cash Receipt, Credit and Collections, and Field Services. The final list consisted of 45 CIS and related vendors.

1.3.3 Dissemination of RFI

Once the vendor list was finalized the RFI was emailed directly to vendor contacts on February 28th, 2003. Vendors were given until March 14th to review the RFI and submit responses.

To enhance the coverage of the RFI, it was also posted on the tender section of the CISWorld web site. By doing so, the RFI was received by nine additional CIS vendors.

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[1] CISWorld is a web site, managed by TMG Consulting, dedicated to customer system solutions within the utility and emerging energy industry.

1.4 Purpose of Summary Document

The purpose of this document is to summarize the information presented in vendor responses and provide Newfoundland Power with a guide for reviewing/referencing these responses.

2 Summary of Responses

2.1 Vendors Meeting Some/All Functional Requirements

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
CGI	SAPHIR	√	√	√	√	√	√	√	√	√	√	Yes	Founded in 1976, CGI is the fourth largest independent information technology services firm in North America, based on its headcount. SAPHIR has yet to be implemented in North America. CGI has stated to **xwave** analyst that they might be willing to negotiate an attractive deal with Newfoundland Power, in terms of pricing, in order to achieve a North American installation. Office location with respect to this RFI: Montreal. Subject Matter Expertise resides in Paris. Very high-level RFI response - difficult to determine from response if SAPHIR really meets Newfoundland Power's stated functional

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
													requirements.
Clicksoftware	ClickSchedule									√		Yes	Clicksoftware's business is Field Service Optimization. ClickSchedule is installed at the following Canadian companies: ▪ BC Hydro ▪ AT&T Canada ▪ Bell Canada ▪ Direct Energy (formerly Enbridge) RFI response provided a good description of the solution but did not comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements. In particular, no cost information was provided. No information provided on office locations. The RFI response does not state that the product is modular. However, Clicksoftware responded only to the Field Services functionality requirement which suggests that Field Services can be implemented on a standalone basis.

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
Cogsdale Corporation	Customer Service Management (CSM)	√	√	√	√	√		√	√	√	√	In part	Cogsdale has been delivering CSM systems to the utility marketplace since 1997. The current version, which is now on release 7.0, is one of the most comprehensive complex billing and customer service solutions available today. CSM offers seamless integration with Microsoft Great Plains. Cogsdale is one of only six companies in the world to have earned the designation of Certified Development Organization from Microsoft Business Solutions. Cogsdale has recently been chosen as the utility solution vendor for the Central Services Association, which provide applications for their 120 utility memberships across 7 southeast US states. After full implementation, over 1500 system users, with 1.5 million end customers will be utilizing the CSM software for their utility customer service. The following functionality can be purchased modularly (all others are sold bundled as Cogsdale CSM):

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													▪ Cash receipt/POS ▪ Field Services Cogsdale's RFI response was good, followed the desired format and addressed all information requirements. Head office and majority of team located in Atlantic Canada (Charlottetown).
Conversant	Customer Watch ^{TM}	√		√	√	√	√		√			No	Conversant is a "new vendor in this space". Customer Watch ^{TM} is not a component-based system. The response states that the solution's architecture allows it to be integrated into virtually any environment, regardless of hardware or software. Offices are located in Texas and Missouri. RFI response provided an overview of the solution but did not fully comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements.

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
CORE Business Technologies	One-Step	√										Yes	CORE has been in business for 15 years and is a provider if payment processing solutions for utilities, cities, counties and universities across the United States. CORE provides cash receipt software and hardware. Based in East Providence, Rhode Island. RFI response provided a good description of the solution but did not comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements. In particular, no cost information was provided.
Docucorp	Docuflex		√									Yes	Docucorp is a leading bill print software provider for the utility marketplace in North America. Nearest sales location: Toronto . Nearest support location: Bedford, New Hampshire. Key customers include: Toronto Hydro, Niagara Mohawk, Southern Company, Exelon Corp,

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													Ameren, MidAmerican, Orange & Rockland, Atco Itek. A sample utility invoice was included with response. Docucorp's RFI response was good, followed the desired format and addressed all information requirements.
Group 1	DOC 1 Suite		√	√					√		√	Yes	Group 1 was founded over 20 years ago and counts over 75% of the Fortune 500 as customers. Nearest service/support location: Toronto. Primary technology partners: Siebel, Informatica. Group 1 responded to Specialized Billing and CRM functionality requirements, however, the information in the response regarding these functionalities is somewhat weak in terms of DOC 1's fit with Newfoundland Power's needs in these areas. Group 1's response followed the desired format

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													but was disjointed and disorganized. Information provided did not meet with requirements in some cases.
Hansen Technologies	HUB Unified		√	√	√	√		√	√	√	√	Yes	Hansen has been in the IT industry for 30 years and the billing market for over 20 years. Hansen has over 100 major CIS clients; approximately 60 of these are HUB Unified clients. Does not provide Cash Receipt functionality but recommends *Cashier for Windows* by Systems Innovators for this purpose. Nearest service/support location: San Diego, California. Primary technology partners: Oracle, IBM, Microsoft, BRIO, Tele-works, System Innovators, Sprint. RFI response did not comply with the prescribed format and provided an excess of information. No meaningful cost information was provided.
Itron	Service-Link									√			Itron is the world's leading technology provider to the energy and water industries for collecting,

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
													analyzing, and applying critical data about electric, gas, and water usage. RFI response provided a good description of the solution but did not comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements. In particular, no cost information was provided.
Kinetiq	PV2		√	√			√					Yes	Kinetiq has nine years' experience in international energy markets. PV2 is currently deployed in 36 companies operating in Canada. Kinetiq's Print Bill functionality appears weak. Primary technology partners: Oracle, Microsoft. RFI response provided a good description of the solution but did not comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements. In particular, no cost information was provided.
Nexus Energy Software	ENERGYprism			√				√			√	Yes	Nexus was founded in 1997 and has approximately 50 employees. Nexus currently works with over 40 of the largest utilities in North America.

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
													Nearest service support locations: Boston, MA and southern Vermont. Primary technology partners: Microsoft, edocs. Supplied a demo with RFI response. RFI response provided a good description of the solution but did not comply with the prescribed format. As a result, the response did not address all of Newfoundland Power's information requirements.
Open-c Solutions	Open-CIS	√	P	√	√	√		√	√	√	√	Yes	Open-c was founded in 1998 and has been chosen by Accenture as the most advanced best-of-breed billing solution available in the market today. Open-CIS performs some of Newfoundland Power's desired Print Bill functionality, but not all. Primary technology partners: Microsoft, Seagate Software (Crystal Reports), SyncSort (file sort and merge), Computer Associates (AutoSys Batch Scheduler), Melissa Data

Vendor	Solution	Cash Receipt/ POS	Print Bill	Specialized Billing	Area Lights/ Special Products	Credit and Collections	Load management	CIS Specific Analysis / Decision Support Tools	Basic CRM	Field Services	Bill Inquiry / Analysis	Modular Sales / Implementation	Commentary
													(address Hygiene), and others. In addition, Open-c's integration partner, Accenture, has strong relationships with several technology vendors. Nearest service/support location: Open-cIS is supported out a Development Center in Minneapolis, MN and out of the corporate headquarters in Santa Ana, CA. Open-c's RFI response was good, followed the desired format and addressed all information requirements. In particular, an excellent cost assessment was provided.
SPL Worldgroup	CorDaptix	√	√	√	√	√		P	√	√	√	In part	SPL is the premier international provider of customer management solutions for the energy and services industries. Modular nature of functionality is questionable. Nearest service/support location: Morristown, New Jersey. Primary technology partners: BEA Systems Inc., BearingPoint Inc., Docucorp, Group1, HP, IBM, Logica, Micro Focus, Oracle, PeopleSoft,

Vendor	Solution	Cash Receipt/ POS	Print Bill	Specialized Billing	Area Lights/ Special Products	Credit and Collections	Load management	CIS Specific Analysis / Decision Support Tools	Basic CRM	Field Services	Bill Inquiry / Analysis	Modular Sales / Implementation	Commentary
													SAGA Software, Siebel. SPL's RFI response was good, followed the desired format and addressed all information requirements.
Talgentra	Gentrack	√	P	√	√	√		√	√	√	√	Yes	Gentrack has been in operation for more than 14 years and has more than 30 customers around the world. Sister product: Tallyman (credit & collections). Billing engine can perform bill design /formatting but all desired Print Bill functionality is not resident in Gentrack – third party vendor would be required (for inserts, envelopes, etc.). Primary technology partners: Microsoft, Oracle and IBM. Nearest service/support location: Baltimore, Maryland. Talgentra provided an excellent RFI response, following the desired format and clearly addressing all information requirements.

Vendor	**Solution**	**Cash Receipt/ POS**	**Print Bill**	**Specialized Billing**	**Area Lights/ Special Products**	**Credit and Collections**	**Load management**	**CIS Specific Analysis / Decision Support Tools**	**Basic CRM**	**Field Services**	**Bill Inquiry / Analysis**	**Modular Sales / Implementation**	**Commentary**
Wishbone Systems	Wishbone Service Suite								√	√		Yes	Wishbone Systems has been in business for almost 10 years. The future direction of Wishbone Systems is to expand its presence as the leading worldwide provider of real-time field service management and optimization systems that leverage clients' existing business systems infrastructure. The Service Suite is built with Microsoft components. Nearest service support location: Englewood Cliffs, New Jersey. Primary technology partners: Wishbone Systems' primary technology partner is Microsoft. Integration alliances in place with Remedy, Peregrine, Tivoli, and CA – several others are pending. SPL's RFI response was good, followed the desired format and addressed all information requirements.

<u>Key</u>
√ – denotes that vendor response indicates functionality is present in solution
P – denotes that vendor response indicates functionality is present, *in part*, in solution.

2.2 Other Respondents

Caselle

Caselle did not formally respond to the Request for Information. Instead, a company representative forwarded a product information package to **xwave**, stating clearly that Caselle is not interested in bolting to Newfoundland Power's current CSS.

Caselle is a leader in local government software solutions. Based on the information package submitted, Caselle's product does not appear to meet Newfoundland Power's requirements

eCredit

eCredit also did not formally respond to the RFI. After reading the RFI document, eCredit noted that its solution may not meet Newfoundland Power's needs. The company forwarded a solution profile to **xwave**, including the following high-level description:

> In short, eCredit has 9 years of experience in delivering credit and collections solutions to commercial organizations. These are non- utilities, non regulated commercial entities who assess the risks associated with extending credit (terms) to other commercial entities. I noticed that consumers represent a portion of the Utilities' customer base. If there is an interest in commercial risk assessment, then perhaps eCredit would be a closer fit.

Project Title: **Network Infrastructure**

Location: **Various**

Classification: **Information Services**

Project Cost: **$393,000**

Description: This is the second year of a two year project that will see the obsolete components of the Company's Network Infrastructure replaced.

Operating Experience: The Network Infrastructure is comprised of technical components such as routers and switches that interconnect computers and applications across the Company. These components all work together to enable the transport and sharing of SCADA data, VHF radio, and corporate data between the Company's computers across the province. For example, serving customers in Corner Brook requires Customer Service System information to be transmitted from St. John's over the Network Infrastructure to a cashier's personal computer in Corner Brook.

The network components that will be replaced in 2003 and 2004 are considered obsolete, either for technical or functional reasons. Technical obsolescence occurs when a technology component becomes either outdated or unreliable, or when the vendor that developed the component no longer supports it. Functional obsolescence occurs when the business requirements of a system change to the point where the component is incapable of providing the required functionality. BearingPoint (formerly known as KPMG Consulting Inc.) states, "Computer and network hardware (e.g., computers, printers, routers, and bridges) typically have a life cycle of two to five years."[1] The average age of all network components being replaced in year two of this project is seven years.

Justification: The corporate network is the foundation for the operation of such critical applications as the Customer Service System and the Problem Call Logging System. The Company's Network Infrastructure across the province contains components that are no longer manufactured. Vendor support for these components is also in decline. The Company's continued use of technically obsolete network components exposes these applications to an unacceptable risk of disruption. The replacement of the obsolete network components will

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[1] BearingPoint (formerly known as KPMG Consulting .) provides business consulting and systems integration to companies and government organizations. They have approximately 16,000 professionals in 39 countries with an average of 12 years of industry-specific experience. They access the latest technology information through nearly 50 alliances with leading software and hardware companies.

ensure the continued stability of the corporate network, thereby avoiding disruptions to customer service and the interruption of critical communications. As well, network components that are no longer adequate due to functional obsolescence will be replaced, allowing for growth in the infrastructure.

The components to be replaced in year two of this project include:

- Seven Motorola 6520 routers that are currently seven years old. These routers are no longer manufactured and vendor support is diminished.
- Two Nortel phone switches and a Redcom radio switch currently thirteen years old which are no longer supported by the manufacturer.
- Seven (7) DECHubs purchased from Digital Equipment Corporation (DEC) prior to 1996. DEC sold off the entire Networking division prior to their acquisition by Compaq. These devices are no longer supported by any vendors.

The Company considered two alternatives when assessing options for moving forward with this initiative:

1) Continue to operate the existing components in the corporate network thus saving the cost of investment at this time. Failure to make the investment at this time would put the normal operation of the Company's Network Infrastructure at an unacceptable level of risk. Should the Network Infrastructure fail the Company's ability to serve customers and to monitor and control the electrical distribution system would be diminished. Vendors no longer manufacture many of these components and technical support for them is decreasing. If one of these components failed due to age, we would not be able to call on the manufacturer for help or get a replacement. Instead we would have to purchase the new equipment at that time causing significant delays that would hinder the Company's ability to function in that area. For example, the DecHUBs have been the cause of several network interruptions in the area offices due to their inability to communicate with newer laptop technology. This problem could not be resolved until the offending laptop was found and disconnected from the network. The vendor has no fix for this problem other than replace the component.

   Many of the components no longer have sufficient capacity to meet the requirements of the Company's applications. Replacing the network components with vendor-supported components will eliminate reliance on obsolete technology and provide capacity to connect shared servers in the future. The new equipment will be supported by the vendor for upgrades, troubleshooting and parts. Also, the new equipment will allow for growth as they can support increased requirements.

   For these reasons, continuing to operate the existing components is not an acceptable risk.

2) Replace the network components with vendor-supported components with increased capacity for future growth.

The benefits of replacing these network components include:

- Eliminating the Company's dependence on technology that is no longer manufactured.
- Reducing the risk of a network failure associated with components for which vendor support is in decline.
- Increasing our ability to remotely monitor and administer network components across the province from a central location.
- Reducing the number of spare parts needed to support the corporate network.
- Reducing the risk of future obsolescence by aligning with a market-leading vendor.

Project Title: **Shared Server Infrastructure**

Location: **Various**

Classification: **Information Services**

Project Cost: **$644,000**

Description: The project involves the addition, upgrade and replacement of computer hardware components and related technology associated with the Company's shared server infrastructure to ensure that the Company continues to provide effective customer service and to operate efficiently.

Operating Experience: The Shared Server Infrastructure project includes the procurement, implementation and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

Technology components such as servers and disks require on-going investment to ensure that they continue to operate effectively. To maintain this effectiveness, investment in additions, upgrades, monitoring and security is essential.

An upgrade is a modification that extends the useful life of a technology component by fixing known problems, improving usability, and providing additional features and functionality. Hardware upgrades are also necessary to accommodate software enhancements, and include such things as adding extra disk storage or tape backup units.

In order to ensure high availability of applications and minimize the vulnerability of its computer systems to external interference, the Company invests in availability monitoring and proactive security monitoring tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or damage or destroy Company information.

Eventually the individual components of technology (servers, disk drives, tape drives, processors and memory chips, etc) will require complete replacement as they become obsolete; the challenge is to make appropriate judgments as to when it is more cost effective to add or replace technology components rather than invest in further upgrades.

Factors considered in determining when to upgrade, replace or add server components include the current performance of the components, the level of support provided by the vendor, the criticality of the applications running on the shared server components, the ability of the components to meet future growth, the cost of maintaining and operating the components using internal staff and the business or customer impact if the component fails. Gartner states that computer servers have a useful life of approximately 5 years.[1] However, Newfoundland Power has extended the useful life of many of its servers, with approximately 30% of servers currently 5 years or older.

Justification: The Shared Server Infrastructure is vital to the provision of low cost, efficient and reliable service to customers. The need to replace and modernize information technology infrastructure is fundamentally the same as the need to replace and modernize the components of the Company's electrical system infrastructure as it deteriorates or becomes obsolete. Instability within the Shared Server Infrastructure has the potential to impact high numbers of employees and customers and therefore is critical to the Company's overall operations and to the provision of overall customer service. The purchase of the components for this project will be tendered in order to ensure they are obtained at least cost. The benefits of the shared server infrastructure project include:

- Ensuring that corporate applications, such as the Customer Service System and the Problem Call Logging System, are available for employees to serve customers.
- Allowing proactive monitoring of the Shared Server Infrastructure to help predict component failure, thus reducing application downtimes that can disrupt the Company's ability to operate and serve its customers.
- Eliminating the Company's dependence on technology that is either no longer manufactured, is obsolete or for which vendor support is in decline.
- Improving security management to ensure that corporate applications and data are adequately protected from external risks.
- Providing additional processing capacity to meet the needs of new or enhanced applications.
- Providing backup for Company data and critical computer components in the event of a serious failure within the Shared Server Infrastructure.

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand technology and drive business growth. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 80 locations worldwide.