NEWFOUNDLAND POWER
A FORTIS COMPANY

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HAND DELIVERED

October 5, 2005

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

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

Ladies & Gentlemen:

**Re: Newfoundland Power 2006 Capital Budget Application**

Please find enclosed the original and six copies of Newfoundland Power's responses to Requests for Information PUB-59.0 NP to PUB-64.0 NP.

For convenience, responses are provided on three-hole punched paper.

A copy of this letter, together with enclosures, has been forwarded directly to Mr. Geoffrey P. Young of Newfoundland and Labrador Hydro and Mr. Thomas J. Johnson, the Consumer Advocate.

If you have any questions regarding the enclosed, please contact the undersigned at your convenience.

Yours very truly,

Peter Alteen
Vice President, Regulatory Affairs
and General Counsel

Enclosures

c. Geoffrey P. Young
Newfoundland & Labrador Hydro

Thomas J. Johnson
Consumer Advocate

**Q.** **<u>GENERATION HYDRO</u>**

**PUB 59.0**

***B-4 Plant Refurbishment – Petty Harbour $1,829,000***

**Board Order P.U. 35(2003), p. 8, states, in referring to discussions between the utilities regarding the upgrade of generation facilities, that "…the Board finds it appropriate that a utility undertake such discussions and document the results as part of the application." Please provide evidence of any such discussions that have taken place regarding the refurbishment of the Petty Harbour Hydroelectric Generating Plant or explain why such discussions did not take place.**

A. ***General***

No evidence of specific discussions between Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") related to the proposed refurbishment of the Petty Harbour Hydroelectric Generating Plant (the "Petty Harbour Project") exists. However, discussions related to generation planning for the integrated island electric system (the "Island Grid") occur on an ongoing basis between the two utilities.

The fact that discussions relating specifically to the Petty Harbour Project did not take place, does not raise any serious issue "…that needless expenditure is not being caused by duplication of services or lack of sharing of resources…"[1] on the Island Grid.

***Joint Planning***

Newfoundland Power and Hydro review matters that address efficiency and duplication in the power system in planning meetings. For example, the last planning meeting between the utilities was held on April 20, 2005. Among the issues related to the Island Grid discussed were: the supply to the Pasadena / Marble Mountain area; St. John's 230/66 kV transformer capacity; the supply to the Voisey's Bay Nickel (Argentia) area; and the generation planning for the Island Grid.

Newfoundland Power's and Hydro's discharge of their joint responsibility to ensure that duplication of services or resources not result in additional costs for customers is ongoing and continuous. It has not typically involved joint evaluation of projects such as the Petty Harbour Project. It has involved regular consultation regarding system planning for the Island Grid which provides a common basis for evaluation of expenditures such as the Petty Harbour Project by both Newfoundland Power and Hydro. Regular consultation regarding system planning for the Island Grid has been, and continues to be, a prominent feature of the relationship between the two utilities.

[1] See Order No. P.U. 35 (2000), p. 8.

One result of such regular consultation is a mutual understanding between Newfoundland Power and Hydro as to the appropriate means of evaluating the economics of refurbishing existing small hydroelectric plants. The mutual understanding is that the economic viability of projects such as the Petty Harbour Project are properly assessed by comparison to the cost of oil at Holyrood.

***The Petty Harbour Project***

Newfoundland Power's economic analysis of the future costs associated with the Petty Harbour Project indicates a levelized energy cost from the plant of 2.777 cents per kWh (see Report *1.2 Petty Harbour Hydro Plant Refurbishment Appendix C*: *Feasibility Analysis).* This is considerably less than the 5.849 cents per kWh cost of oil at Hydro's Holyrood thermal generating plant[2]. Given the large difference in the forecast energy cost of the Petty Harbour Project and Holyrood fuel costs, the economics of the Petty Harbour Project clearly justify the proposed expenditure.

The *Snook's Arm Wood Stave Penstock; Evaluation, Recommendation and Estimated Cost for Replacement* project which is part of Hydro's 2005 capital program was economically justified on a similar footing.[3]

Holyrood fuel costs practically represent the avoidable cost of generation on the Island Grid. It is an appropriate benchmark for evaluating the economic viability of refurbishment of small hydroelectric facilities on the Island Grid. Use of this benchmark reflects the fact that a reduction in generation on the Island Grid would directly increase the amount of oil consumed and therefore contribute to increased overall production costs.[4]

***Concluding***

The fact that no specific discussions were undertaken between Newfoundland Power and Hydro concerning the Petty Harbour Project was due to oversight on the part of the Company. Newfoundland Power will ensure such oversight does not reoccur.

In the context of overall planning for the Island Grid, the Petty Harbour Project (i) is economically justified and (ii) will not involve needless expenditure caused by duplication of services or lack of sharing of resources as between Newfoundland Power and Hydro.

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[2] Based on 630 kWh per bbl and oil at $C 36.85/bbl as per Hydro letter to the Board of April 14, 2005.
[3] See Hydro's 2005 Capital Budget Application, Section G, Tab 1.
[4] For a more detailed explanation of generation planning as it applies to the refurbishment of these relatively small hydroelectric generating plants, please refer to the response to PUB 60.0.

**Q.** **GENERATION HYDRO**

**PUB 60.0**

**Under what circumstances would NP consider a hydroelectric plant to be unworthy of refurbishment and incapable of providing further service?**

A. ***General***

Newfoundland Power would typically consider a hydroelectric plant to be unworthy of refurbishment and incapable of providing further service when the cost of refurbishment would result in the plant's production being uneconomic.

The following provides an outline of how the economics of hydroelectric plant refurbishment is evaluated by Newfoundland Power.

***Background: System Planning and Operations***

Newfoundland Power's hydroelectric plants are part of the integrated island electric system (the "Island Grid") and decisions regarding the refurbishment of the plants are made in the context of the planning and operational economics of the Island Grid.

The key elements in generation planning and operations are the safe and reliable production of electricity; meeting the electricity requirements of customers at all times; and minimizing overall production costs.

Since the development of the Bay'D'Espoir hydroelectric project, the ongoing Island Grid planning process has been managed by Newfoundland and Labrador Hydro ("Hydro"). The starting point in the planning process is the forecast of energy and demand for the Island Grid which is updated on a regular basis. Hydro prepares the forecast based on information from its customers, including Newfoundland Power, and its own use. These forecasts extend over the period of the generation plan, typically 20 years or more. Hydro compares these forecasts with the existing generation capability on the Island Grid to meet energy and demand. When capacity to meet either is exceeded by the forecast, then new generation is planned to be added to the Island Grid at that time.

All generation on the Island Grid is operated so as to ensure customer demand is met on a least cost basis.

***Hydro Plant Refurbishment: Short Term and Long Term Economics***

A key economic principle underpinning least-cost operation of the Island Grid is the minimization of variable costs in the short term. This is because the fixed, or sunk, costs are not subject to change and are therefore not affected by operation of the system.

The variable costs of the Holyrood generating station are the appropriate benchmark of *short term* variable, or marginal, cost on the Island Grid. Under current circumstances, this cost is on the order of 5.8 cents per kWh.[1] As a general rule, oil costs are minimized by maximizing the hydroelectric generation production on the Island Grid.[2] For every kWh that is produced from existing hydroelectric resources, a corresponding kWh at Holyrood is not required and a reduction in thermal plant costs of 5.8 cents per kWh is achieved.

A key economic principle underpinning least-cost planning of the Island Grid is the minimization of long term costs.

In the longer term, if a relatively small hydroelectric plant were shut down instead of being refurbished, it would (i) increase the production requirement at Holyrood and (ii) at least conceptually, advance the need for new generation.[3] As a result, in the long term, refurbishing a hydroelectric plant will (i) avoid the cost of production at Holyrood and (ii) tend to delay the need for new generation.

If the cost associated with refurbishing a hydroelectric plant results in a higher unit cost than the cost of Holyrood fuel, then additional matters will come into the consideration of whether refurbishment of the plant is justified. A principal consideration will be the relative cost of refurbishing the hydroelectric plant compared to the cost of alternative generating capacity additions. If there are other more economic alternatives, the least cost alternative may be retirement of the hydroelectric plant.

Because the cost of new generation will normally exceed the cost of generation from existing facilities, assessing the viability of refurbishing an existing hydroelectric generator by comparing it to avoided cost of burning oil at Holyrood over the long term is conservative.

In summary, so long as the forecast levelized unit cost of refurbishing a hydroelectric plant is less than the forecast fuel cost at the Holyrood thermal plant, the refurbishment should be economic in both the short and long terms.

***Other Considerations***

Another consideration in addressing the possible retirement of a hydroelectric plant, is its value in improving reliability of supply to a local area. For example, in circumstances where a transmission link to the main grid fails, the plant may be capable of restoring service to some or all customers. The value of this consideration, which has obvious qualitative aspects, must be evaluated in the context of the additional cost involved.

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1 Based on a plant incremental efficiency of 630 kWh / bbl and current oil price in customer rates of C$36.85 bbl.

2 In minimizing oil costs in ongoing Island Grid operations, Hydro will also have regard for ongoing water resources so as to ensure that sufficient water resources are available to meet both system peak and year round energy requirements on the Island Grid.

3 Whether or not new generation is actually advanced will depend upon the planning horizon considered, the forecast annual increase in demand and energy, and the size of the hydroelectric plant being shut down.

**Q.** **<u>DISTRIBUTION</u>**

**PUB 61.0**

***<u>B-25 Extensions (Pooled) $6,766,000</u>***
**IR PUB-11.0 NP (2006 NP Capital Budget), Tables 1 and 2 indicate that in each year from 2001 to 2005F the expenditures for extensions and the number of new customer connections have been consistently under-forecast, Table 1 by an average of 44%, Table 2 by an average of 33%. Why, given the variances between budget and actual, does NP continue to use the same methodology of estimating costs relating to the connection of new customers?**

A. ***General***

The current methodology is based on the historic unit cost of connecting new customers and the forecast number of new customers.

The relatively large variances between budget and actual for the Distribution project *Extensions* has not been the result of methodological deficiencies in the estimation of the unit costs of connecting new customers. The variances are principally explained by the relatively large difference between the forecasts of new customers and the actual number of new customer connections made.

***Unit Cost Methodology***

In early 2005, Newfoundland Power conducted an analysis of 2004 Distribution capital cost variances affected by customer growth. The analysis concluded that the almost $3.5 million 2004 capital expenditure variance in the *Extensions* project was not materially affected by differences in budgeted and actual unit costs.

A copy of the report entitled *An Analysis of 2004 Distribution Capital Expenditure Variances Affected by Customer Growth* which was filed by the Company on March 1, 2005 with its 2004 Capital Expenditure Report is Attachment 1 to this response. It contains the results of Newfoundland Power's 2005 analysis of 2004 Distribution capital cost variances.

As indicated in the response to PUB-43.0 NP, Newfoundland Power has made some refinements to its unit cost methodology. These changes, however, were principally driven by an effort to provide improved transparency and consistency in the use of unit costs as contemplated by the Provisional Capital Budget Application Guidelines.

***Forecast vs. Actual Customer Growth***

Newfoundland Power's forecast of new customers historically has been derived from the annual forecast of the *Conference Board of Canada*, an independent forecast service (the "Conference Board"). The Conference Board's housing starts forecast for the province is adjusted to provide a forecast of housing starts for Newfoundland Power's service territory. In recent years, the Conference Board's forecasts have underestimated housing starts for Newfoundland and Labrador.

In an effort to improve the accuracy of the customer forecast for purposes of the Company's 2006 capital budget, Newfoundland Power has modified its customer forecasting methodology by including information from the housing starts forecast of *Canada Mortgage and Housing Corporation* (CMHC), a federal Crown corporation. Since 2002, CMHC's forecasts of housing starts for Newfoundland and Labrador have proved to be more accurate than those of the Conference Board.

***Concluding***

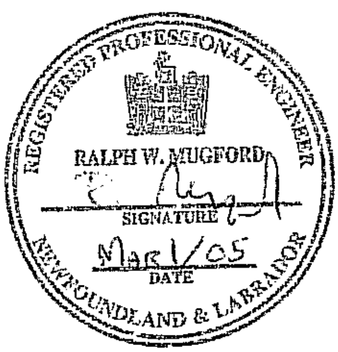
There have been relatively large variances between budgeted and actual costs in the Distribution project *Extensions* in recent years.

Newfoundland Power continues to use the same methodology because the variances are principally related to the accuracy of independent economic data as opposed to a methodological deficiency.

Newfoundland Power has taken steps to address the accuracy of the economic data used for forecasting the number of new variances in its 2006 capital budget.

# An Analysis of 2004 Distribution Capital Expenditure Variances Affected by Customer Growth

# An Analysis of 2004 Distribution Capital Expenditure Variances Affected by Customer Growth




**Ralph Mugford, P.Eng**
**Senior Engineer**

**March 1, 2005**

## 1. Introduction

Newfoundland Power's actual 2004 capital expenditures in the Distribution class were approximately $3.4 million over budget. The primary cause of actual expenditures exceeding budget was the increase in actual capital expenditure required to serve new customers.

This Report analyzes variances between budgeted and actual 2004 capital expenditures for each of the Distribution projects which are materially impacted by the capital cost of serving an increased number of customers.

The analyses contained in this Report clearly support the conclusion that increased 2004 capital expenditures were the result of the unexpected increase in the number of new customers. The analyses do not, however, reconcile budgeted and actual 2004 capital expenditure for the Distribution classes reviewed. Such a reconciliation is practically impossible.

## 2. Overview

A comparison of budgeted and actual capital expenditures in those Distribution projects affected by customer growth is set out in Table 1 below.

**Table 1**
**2004 Capital Expenditures**
**in Distribution Projects Affected by Customer Growth**
**($000s)**

| Project | Budget | Actual | Variance |
|---|---|---|---|
| Extensions | 4,956 | 8,406 | 3,450 |
| Meters | 1,174 | 1,297 | 123 |
| Services | 1,946 | 2,008 | 62 |
| Street Lighting | 1,242 | 1,499 | 257 |
| Transformers | 4,965 | 5,449 | 484 |
| **Total** | **14,283** | **18,659** | **4,376** |

Newfoundland Power forecast an additional 2,313 gross domestic customer connections in 2004. Actual gross domestic customer connections in 2004 were 3,632, or 57% more than forecast. Details on the forecast and actual 2004 gross customer connections are set out in Table 2 below.

**Table 2**
**2004 Gross Domestic**
**Customer Connections**

| **Area [1]** | **STJ** | **AVA** | **BUR** | **BON** | **GAN** | **GFW** | **CBK** | **STV** | **Total** |
|---|---|---|---|---|---|---|---|---|---|
| Forecast | 1,188 | 344 | 72 | 156 | 144 | 130 | 154 | 125 | 2,313 |
| Actual | 2,128 | 384 | 154 | 79 | 213 | 205 | 319 | 150 | 3,632 |
| **Difference** | **940** | **40** | **82** | **(77)** | **69** | **75** | **165** | **25** | **1,319** |

## 3. Extensions

Actual 2004 capital expenditures on Distribution Extensions were $3,450,000 more than the 2004 capital budget.

For 2004, Newfoundland Power forecast a unit cost per new customer for Distribution Extensions of $2,143.[2] The 2004 Distribution Extensions budget of $4,956,000 explicitly reflected this unit cost and the 2004 forecast gross domestic customer connections of 2,313 as set out in Table 3 below.

**Table 3**
**Distribution Extensions**
**2004 Capital Budget**

| **Forecast GDCC [3]** | **Unit Cost ($)** | **Budget ($000s)** |
|---|---|---|
| 2,313 | 2,143 | 4,956 |

Actual 2004 gross domestic customer connections were 3,632. Application of the 2004 forecast unit cost to actual gross domestic connections indicates that the increased number of connections was the primary cause of increased Distribution Extensions capital expenditures. This is reflected in Table 4 below.

[1] STJ = St. John's Area; AVA = Avalon Area; BUR = Burin Area; BON = Bonavista Area; GAN = Gander Area; GFW = Grand Falls Area; CBK = Corner Brook Area; STV = Stephenville Area..

[2] See Response to Information Request PUB 27.3, Page 1 of 5 filed in Newfoundland Power's 2005 Capital Budget Application.

[3] Forecast gross domestic customer connections.

**Table 4**
**Distribution Extensions**
**2004 Capital Budget**

| Forecast GDCC [3] | Unit Cost ($) | Budget ($000s) |
|---|---|---|
| 3,632 | 2,143 | 7,783 |

The difference between the 2004 capital expenditure based upon unit costs and indicated in Table 4 above and the total Distribution Extensions capital expenditure of $8,406,000 is $623,000. This difference is explained by 2004 capital expenditures associated with the Humber Valley Report (the "HVR").

Due to the special circumstances associated with extending service to HVR, the costs associated with the extension were not reflected in Newfoundland Power's 2004 unit cost budgeting.[4]

## 4. Meters

Actual 2004 capital expenditures for Meters totaled $123,000 more than the 2004 capital budget.

This increased expenditure broadly reflects the increased number of gross domestic customer connections in 2004 as indicated in Table 5 below.

**Table 5**
**Meters**
**2004 Capital Expenditures**

| | | Expenditure Increase ($000s) | |
|---|---|---|---|
| Increased GDCC[5] | Unit Cost ($)[6] | Indicated | Actual |
| 1,319 | 102 | 135 | 123 |

## 5. Services

Actual 2004 capital expenditures on Services were $62,000 more than the 2004 capital budget. This was principally the result of two of factors.

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4 In 2004, the Board approved contributions in aid of construction relating to approximately $400,000 in main line distribution extensions related to HVR (see Order Nos. P.U. 15 and 29 (2004)).
5 Increased gross domestic customer connections over forecast.
6 See Response to Information Request PUB 27.3, Page 1 of 5 filed in Newfoundland Power's 2005 Capital Budget Application.

In 2004, the total cost of replacement Services was lower than anticipated in the 2004 capital budget. The 2004 capital budget contained $494,000 for replacement Services. In 2004, actual expenditures on replacement Services was $349,000. The fact that actual 2004 replacement Services capital expenditures were lower than budget tends to mask the overall impact of increased new Services costs on total Services capital expenditures. When the decreased capital expenditures associated with replacement Services is considered, the total variance over budget for capital expenditure for new Services is approximately $207,000.

The $207,000 increased capital expenditure on new Services in 2004 appears disproportionately low when compared to the increases in the other Distribution projects affected by customer growth. The likely cause of this is the fact that the bulk of additional customer connections in 2004 (more than 70%) was experienced in new residential subdivisions in the St. John's area. The connection of new Services in new subdivisions tends to be low-cost. Part of this is due to the close proximity of a relatively large number of new connections. Part of it is due to the low requirement for service poles. Typically, an installed service pole will add approximately $1,000 to the capital cost of a new Service.

## 6. Street Lighting

Actual 2004 capital expenditures on Street Lighting were $257,000 more than 2004 capital budget.

The only material variance between actual 2004 Street Lighting capital expenditures and the 2004 Street Lighting capital budget occurred in the St. John's area. The variance was $270,000.

The bulk of additional customer connections was in St. John's in 2004 and was associated with new residential subdivisions. In 2004, Newfoundland Power extended distribution service to 59 subdivisions in the St. John's area. This compares to 33 subdivisions in 2003. Actual Street Lighting installations in 2004 were 57% higher than in 2003. This corresponds to the increased 2004 customer growth over forecast.

## 7. Transformers

Actual 2004 capital expenditures on Transformers were $484,000 more than the 2004 capital budget.

In 2004 general service growth, in the St. John's area in particular, required a larger number of padmount transformers be installed. Total padmount installations in 2004 were 52 compared to 19 in 2003.

The cost of padmount transformers is in the order of $20,000. Approximately 20 padmount transformers were included in the 2004 capital budget. The actual installation of 52 padmount units in 2004 largely explains the increased transformer expenditures.

**Q. <u>DISTRIBUTION</u>**

**PUB 62.0**

***<u>B-40 Rebuild Distribution Lines (Pooled) $3,190,000</u>***
***<u>B-45 Distribution Reliability Initiative (Pooled) $3,114,000</u>***
***<u>B-48 Feeder Additions and Upgrades to Accommodate Growth (Pooled) $266,000</u>***
**Please explain the distinctions between these three projects.**

***General***

Please refer to Section 2.0 *Capital Budgeting* found at pp. 2 *et. seq.* of the ***2006 Capital Budget Plan*** which explains these three projects in the context of Newfoundland Power's concurrent obligations to (i) maintain its existing network assets which are essential to the provision of service to its customers and (ii) extend or expand the electricity network to meet customers' service requirements.

The Distribution projects *Rebuild Distribution Lines* and *Distribution Reliability Initiative* are aimed at prudent maintenance of existing network assets. The Distribution project *Feeder Additions and Upgrades to Accommodate Growth* is principally aimed at increasing capacity to meet customers' service requirements.

Each project is briefly described below.

***Rebuild Distribution Lines***

Each year Newfoundland Power performs routine field inspections of a portion of the Company's 302 distribution feeders.

This project reflects the annual planned distribution capital maintenance on the approximately 8,200 km of distribution lines that comprise the Company's 302 feeders.

The work performed under this project tends to focus on distribution line components (i.e., transformers, switches, arrestors, etc.) on a *system-wide basis*.

***Distribution Reliability Initiative***

Each year Newfoundland Power performs detailed engineering performance assessments on its poorest performing distribution lines.

The assessments are aimed at improving the performance of the poorest performing distribution feeders. The assessments are necessarily more *local in nature* as opposed to system-wide in nature. The work performed tends to be much broader in scope and typically includes relocation of sections of line or implementation of higher standards to accommodate local weather conditions.

The analysis of each feeder proposed to be upgraded in 2006, together with the broader Company-wide engineering assessment, is contained in ***4.2 2005 Corporate Distribution Reliability Review***.

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

Each year Newfoundland Power must make capital expenditures to its existing distribution network as a result of increasing customer requirements.

Customers' electricity requirements are not static. Increased load growth on a particular feeder may require that a component or system configuration be changed to ensure that the necessary capacity is available to meet that increased customer requirements safely and reliability.

**Q.** **GENERAL PROPERTY**

**PUB 63.0**

***B-57 Standby Diesel Generators – Duffy Place & Clarenville (Pooled) $665,000***

**In light of the listing provided in Volume II, Section 5.1, p. 3, what is the plan to install backup generation at sites other than Duffy Place, Carbonear and Clarenville?**

A. Table 1 lists the area operations buildings noted in the report *5.1 Standby Generation at Newfoundland Power Facilities* and outlines the schedule currently envisioned for the installation or upgrade of standby generation at each facility.

**Table 1**
**Standby Diesel Generators**
**Installation/Upgrade Schedule**

| Building | Year |
|---|---|
| Duffy Place | 2006 |
| Clarenville | 2006 |
| Gander | 2007 |
| Burin | 2007 |
| Grand Falls | To be determined. |
| Corner Brook | To be determined |
| Carbonear | 2009 |
| Stephenville | 2009 |

Further information with respect to the proposed schedule for the installation or upgrade of standby generation facilities at Company buildings is provided in the response to PUB 64.0 NP.

**Q.** **<u>GENERAL PROPERTY</u>**

**PUB 64.0**

**Why is there benefit in deferring the installation of backup generation at sites other than Duffy Place, Carbonear and Clarenville?**

A. As a practical matter, not all justifiable capital projects that have been identified by Newfoundland Power can be completed in a single year. The Company's schedule for installing backup generation at its operations buildings throughout the island reflects this reality. The schedule outlined in the response to PUB 63.0 NP is a phased approach that considers the relative urgency of the requirements for each building in the context of other demands on the Company's resources and the desirability of a measure of consistency in the level of capital spending year over year. The schedule is also influenced by the opportunities that exist for the redeployment of existing generators to other buildings.

As noted in ***5.1 Standby Generation at Newfoundland Power Facilities***, the greatest priority for adequate backup generation is the Duffy Place building, which houses a number of critical electrical loads (including the Company's call centre) and is the home base for line operations in the Northeast Avalon. The proposed redeployment of the existing Duffy Place generator to Clarenville is a cost-effective re-use of equipment based on the fact that the capacity of the unit closely matches the electrical load of the Clarenville building.

For 2007, the Company's current plan is to install backup generation at its Gander and Burin buildings. These locations are considered to be relatively high priority locations given the geographic isolation of Burin and the challenging weather conditions of the northeast coast served by the Gander operation.

The installation of standby generation in Grand Falls and Corner Brook has been deferred until the status of the Company's two buildings at each location has been confirmed. The Company is currently considering the economic and operational feasibility of consolidating its activities in each location in a single building. It is therefore prudent to defer consideration of standby generation requirements for those locations until the Company's plans in that regard have been finalized. If operations are consolidated in these two locations, it will necessitate significant modifications to the remaining buildings. The installation of standby generation would proceed at the same time. This could occur in 2007 or 2008.

The Carbonear facility has backup generation that is capable of supporting approximately 50% of the building's electrical load. Although this level of backup is insufficient for the longer term, it lowers the relative priority of that location. Current plans envision the upgrade of backup generation capacity in 2009, at which time the existing backup generator at Carbonear would be redeployed to Stephenville.