HAND DELIVERED

September 23, 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-36.0 NP to PUB-58.0 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,

Gerard Hayes
Senior Counsel

Enclosures

c. Geoffrey P. Young
Newfoundland & Labrador Hydro

Thomas J. Johnson
Consumer Advocate

Q. **GENERATION HYDRO**

PUB 36.0

B-4 Plant Refurbishment – Petty Harbour

What items among those listed in Table B-1 of *1.2 Petty Harbour Hydro Plant Refurbishment* are considered to be interdependent versus related?

A. Table 1 provides the requested information.

Table 1
Petty Harbour Hydro Plant Refurbishment
Interdependent vs. Related Items

Interdependent Items	**Cost Estimate**
Upgrade Controls G1	$ 80,000
Replace Unit Control PLCs G2	372,000
Replace Electronic Governor G2	86,000
Upgrade Generator Protection and Control G2	184,000
Replace Unit Control PLCs G3	372,000
Replace Electronic Governor G3	86,000
Upgrade Generator Protection and Control G3	191,000
Upgrade Plant AC and DC Systems	79,000
Total Interdependent Items	**1,450,000**
Related Items	
Turbine Overhaul	153,000
Penstock Coating Replacement	226,000
Total Related Items	**379,000**
Total Interdependent and Related Items	**$1,829,000**

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

PUB 37.0

Please provide an economic rationale supporting approval of the expenditures for the related items.

A. The related items, as noted in the response to PUB 36.0 NP, are the turbine overhaul and the penstock coating replacement.

As noted at page 4 of *1.2 Petty Harbour Hydro Plant Refurbishment*, the related items are required to be completed in 2006, regardless of whether the other project items proceed at that time**.**

The turbine overhaul is required to ensure the safe operation of Unit 2 and to enable the unit to produce its rated power output. The penstock coating replacement is required to provide corrosion protection for the penstock and maintain its life expectancy based on recent industry findings.

Completing the two related items at the same time as the interdependent work results in overall cost reductions estimated to be in the order of $35,000. These cost savings result from the elimination of additional site supervision, engineering and administration, as well as contractor-related savings.

Completing all of the items in 2006 also avoids an additional 10-week shutdown of the plant in a later year, which could result in additional spilling of water and associated lost production.

Q. **GENERATION HYDRO**

PUB 38.0
B-7 Port aux Basques Fuel Tank Replacement
Is this project being carried out to meet regulatory requirements? If not, please provide the economic rationale for why this project should be approved.

A. The proposal to replace the Port aux Basques fuel tank is based on responsible environmental stewardship, and is not in response to a regulatory requirement. The proposed replacement is not based on an economic rationale. The fuel tank is 18 years old and is being replaced to reduce the risk of an oil spill.

One of the Company's objectives under its ISO 14001 certified Environmental Management Program is to incorporate the best available technology and upgrade all self-dyked fuel storage tanks by December 31, 2007. As part of this objective, the replacement of the Port aux Basques fuel tank was scheduled for 2006.

Newfoundland Power is committed under its Environmental Management Program to demonstrate continual improvement in environmental matters and to reduce all potential high risk sources of pollution. Implementation of the Environmental Management Program commenced in 1999, and ISO certification was achieved for the Company's generation section in 2001.

In 1999, the Company reported 120 oil spills, of which 12 occurred in generation facilities. In 2004, the number of spills Company-wide totaled 54, of which only 2 took place in generation facilities.

Q. **<u>SUBSTATIONS</u>**

PUB 39.0

<u>B-12 Replacement and Standby Substation Equipment</u>

Please compare, including an explanation for any fluctuations that exceed 10% year over year, the budgetary allowance of $1,023,000 for standby substation equipment with the allowance for the same item (standby substation equipment) in previous years' budgets.

A. *General*

As noted in report *2.2 2006 Replacement and Standby Substation Equipment*, the budgetary allowance of $1,023,000 is comprised of projected expenditures of $660,000 for the purchase of standby substation equipment and $363,000 for emergency replacements. The estimates of the expenditure requirements for these two budget items are based primarily on an assessment of historical actual expenditures for similar items.

Newfoundland Power's capital expenditures requirements for standby substation equipment and emergency replacements depend on the incidence of actual or imminent equipment failures. When equipment is withdrawn from the standby pool to replace failed or failing equipment, the pool must be replenished, necessitating expenditures for Standby Equipment. At the same time, the labour associated with the replacement of the failed equipment, and the acquisition of any non-stock items, will be charged to Emergency Replacements.

Large portions of Newfoundland Power's substation assets in service are approaching the end of their expected service lives. These assets are experiencing physical deterioration due to such causes as corrosion, exposure to the sun's ultraviolet radiation, and damage due to power surges. In recent years, the effects of age on these assets have resulted in a marked increase in unplanned replacements of major substation equipment.

While failures of substation equipment are inevitable, the incidence of failures in any one year cannot be predicted with any degree of accuracy. Given the unpredictable nature of such expenditure requirements, the Company's engineers must estimate future requirements using historical expenditures and recent experience as a guide.

Further complicating the budgeting process is the variety of substation equipment. The equipment for which standby units are required ranges from smaller items, such as potential transformers (PTs) costing between $1,000 and $10,000, to larger items, such as circuit breakers that can range from $30,000 to $100,000 in price.

Variances in failure experience can significantly alter expenditure requirements from one year to the next. For example, the Company acquired 2 circuit breakers for its standby pool in 2004 at a total cost of $85,000; while in 2002, a total of 4 circuit breakers were acquired at a cost of $284,000. In 2002, the Company acquired 3 PTs at a cost of approximately $14,000; while in 2004, a total of 9 PTs were acquired at a cost of approximately $42,000.

Budget vs. Actual Expenditures
Table 1 shows budget amounts and actual capital expenditures comparable to the budgetary allowance of $1,023,000 for the Standby Equipment and Emergency Replacements components of the 2006 Replacement and Standby Substation Equipment project.

Table 1
Replacement and Standby Substation Equipment
2002 to 2006

	Standby Equipment		Emergency Replacement	
Year	**Budget**	**Actual**	**Budget**	**Actual [1]**
2002	443,000	577,000	0	262,000
2003	350,000	415,000	0	166,000
2004	600,000	680,000	0	286,000
2005	600,000 [2]	650,000(F)	250,000 [2]	370,000(F)
2006	660,000	-	363,000	-

1. Actual expenditures for Emergency Replacements for 2002, 2003 and 2004, based on a detailed review of capital work orders.
2. For purposes of this analysis, the $850,000 budgetary allowance for Corporate Spares & Replacements in the Replacement & Standby Substation Equipment project in Newfoundland Power's 2005 Capital Budget has been segmented into its two components.

Variances from budget in this expenditure category are expected to continue, since accurate forecasting is difficult. To explain year over year budget variances to date, it is appropriate that Emergency Replacements and Standby Equipment be considered separately.

Emergency Replacements
The report *2.2 2006 Replacement and Standby Substation Equipment* provides details of the budgeted expenditures included in the Emergency Replacements category.

Prior to the 2005 capital budget, Emergency Replacements were not specifically budgeted in the Replacement and Standby Substation Equipment project. For the most part, the capital expenditures for emergency substation equipment replacements were charged to the Replacement and Standby Substation Equipment project. Depending on the nature of the work, however, certain of the expenditures would have been charged to other Substations projects, such as Rebuild Substations.

In preparing the 2005 budget, it was recognized that these emergency replacement expenditures had reached a material level and, to improve budgeting and cost control, should be budgeted separately. Based on historical expenditures and the judgment of engineering staff, an allowance for emergency replacements of $250,000 was included in the budget for Corporate Spares & Replacements in the 2005 Replacement and Standby Substation Equipment project.

The 2006 budget figure, an approximately 45% increase over the 2005 budget amount, was set in light of actual 2004 expenditures of approximately $286,000 and a forecast expenditure for 2005 of approximately $370,000.

Standby Equipment
The report *2.2 2006 Replacement and Standby Substation Equipment* provides details of the budgeted expenditures included in the Standby Equipment category.

As noted in *General*, the relatively steady increase in substation equipment failures has also influenced Standby Equipment expenditures, which are required to replenish the pool of replacement equipment. While a number of failures can be attributed to storm damage, particularly lightning, most failures of substation equipment are age-related. As can be seen in Table 1, budgeted expenditures in this category have shown an upward trend in recent years, although there was a slight decrease in 2003.

The 2003 budget for Standby Equipment was reduced from the 2002 budget by 28% due to the Company's expectation, at the time the 2003 budget was prepared, that actual requirements for 2003 would be more reflective of the years prior to 2002. Actual expenditures for 2000 and 2001 were approximately $175,000 and $232,000, respectively.

Actual 2002 expenditure requirements were significantly higher than the budget allowance. Together with a forecast variance over the 2003 budget at the time the 2004 budget was being prepared, this influenced the decision to increase the allowance for Standby Equipment for 2004 by 71% as compared to 2003.

At the time the 2005 budget was prepared, the forecast expenditure for 2004 was not materially different than the budget. Consequently, the budget for Standby Equipment was maintained at $600,000 for 2005.

By the time the 2006 capital budget preparations were underway, actual 2004 expenditures were known to have exceeded the budget, and 2005 expenditures were forecast to exceed the 2005 budget as well. In light of these developments, the 2006 budget for Standby Equipment was increased by 10% over the 2005 budget amount.

Concluding
Capital expenditure requirements associated with the unplanned replacement of failed or failing substation assets have been increasing in recent years. Due to the age of substation assets in service, failures are expected to continue to put upward pressure on capital expenditure requirements. Because equipment failures tend to be unpredictable, budgeting appropriate capital expenditure allowances for emergency replacements is

difficult. Consequently, it is expected that variances from budget will continue to occur until the Company's experience of substation equipment failure becomes more stable.

Q. **<u>SUBSTATIONS</u>**

PUB 40.0

<u>B-12 Replacement and Standby Substation Equipment</u>

What, if any, efforts has, is or will NP make to normalize the annual expenditure for this annually occurring budget item?

A. The Company examined the prospect of budgeting expenditures in this category based on average expenditures. However, this approach did not provide expenditure projections that matched actual expectations.

As noted in the response to PUB 39.0 NP, annual expenditure requirements associated with this budget item, especially the emergency replacement component, have increased significantly in recent years. In this context, average historic costs are not a reliable indicator of future expenditure requirements.

Newfoundland Power continually assesses its capital budget process in an effort to identify opportunities to make the budgeting process more transparent. The use of historic average costs to estimate future requirements contributes to this goal; and the Company endeavours to employ this approach where it is practical to do so.

When expenditure requirements for this budget item become more consistent, some form of normalizing, such as historic averaging, may be appropriate. Until this happens, the budget for this item will continue to be based on an assessment of historic expenditures and engineering judgments based on assessments of the factors influencing future expenditure requirements.

Q. **<u>TRANSMISSIONS</u>**

PUB 41.0

<u>B-22 Rebuild Transmission Lines - Re: 3.2.1 Bonavista Loop Transmission Planning</u>

There are only two options explored in the attached economic analysis – a rebuild of 110L and 111L as planned and an upgrade of the 66kV line to 138 kV.

Why didn't NP explore the option to defer this project for 1, 2 or 5 years as a means to compare the NPVs of all options?

A. The purpose of the economic analysis in *3.2.1 Bonavista Loop Transmission Planning* is to compare the alternatives for upgrading the transmission loop, not to establish the timing of the work. A deferral of 1, 2, or 5 years would have resulted in a lower net present value for the cost of each of the two options considered. Consequently, deferral would have been the preferred alternative, based on economic analysis alone.

The proposal to commence the Bonavista Loop project in 2006 is based on the engineering assessment of the condition of the line. As noted in *3.2 110L Transmission Line Rebuild*, the poles, conductor, crossarms and hardware of 110L are deteriorated and in a weakened state. This places the line at risk of more frequent power outages and makes it vulnerable to large scale, widespread damage should it become exposed to heavy wind, ice and snow load. Rebuilding portions of a line under emergency conditions would be more expensive, and less economic, than a planned rebuild project.

The rebuilding of 110L is part of Newfoundland Power's transmission line rebuild strategy outlined in *3.1 Transmission Line Rebuild Strategy*. As noted in that report, the important role transmission lines play in providing reliable service to large numbers of customers requires they be rebuilt before they deteriorate to the point that they fail in service.

Commencing the rebuild in 2006 as proposed is intended to ensure the continued provision of safe, reliable electrical service. It is the judgment of Newfoundland Power that deferral of the proposed rebuild of 6.7 kilometres of 110L is not an appropriate option for consideration.

Q. **<u>TRANSMISSIONS</u>**

PUB 42.0

Is there evidence that the lines in question are in imminent peril or likely to fail in the next 12 months?
If so, what is the calculated probability of such failure?
If not, what rationale can NP provide for proceeding with this project in 2006?

A. As noted in the response to PUB 41.0 NP, the evidence with respect to the condition of 110L is outlined in *3.2 110L Transmission Line Rebuild*. This evidence, which is outlined in Section 2.0 of the report, consists of the results of a detailed inspection of the components of the line that revealed evidence of substantial deterioration of numerous components; the fact that the line has been de-rated to 30% of its design capacity due to deterioration of the conductor; and, the incidence of unplanned outages on the line.

Design standards for transmission lines are established having regard to local weather conditions. Since the construction of 110L in 1958, the applicable design standards have increased as a result of the severe weather recorded in the area. Given the existing condition of the line, there is a likelihood that the line would fail in a significant way if the weather conditions approached the design parameters.

The proposal to rebuild a portion of 110L is made in the context of Newfoundland Power's transmission line rebuild strategy outlined in *3.1 Transmission Line Rebuild Strategy*, and is based on objective assessment of the observed condition of the line. As noted in that report, the important role transmission lines play in providing reliable service to large numbers of customers requires they be rebuilt before they deteriorate to the point that they fail in service.

Newfoundland Power has not calculated the probability of imminent failure of the line. Such a calculation would involve an assessment of a number of variables that are difficult to estimate with any degree of confidence. In Newfoundland Power's judgment, it would not be prudent to schedule major transmission line capital work on the basis of such a calculation.

Q. DISTRIBUTION

PUB 43.0

B-25 Extensions

Per Table 2, the unit costs data for 2005F is based on total new customers of 3,771. However, the number of new customers for 2005 is given as 3,161 in Note 4 of the 2005 Capital Expenditure Status report (Appendix A p.3 of 5).

Please explain the difference.

A. *General*

In accordance with the Provisional Capital Budget Application Guidelines issued by the Board on June 2, 2005 (the "Provisional Guidelines"), Newfoundland Power has attempted, where possible, to modify its capital budgeting process to accommodate the goals of improved transparency and consistency in budgeting. For the Distribution budget category, the Company has adopted a framework whereby budget estimates are derived using one of three methods.

For projects where the nature and scope of the work could be determined at the time the budget is prepared, budget estimates were based on detailed engineering assessments. Such projects are typically directed at identified needs, and the work is capable of advance planning and scheduling. The Distribution projects that were estimated in this manner are the Distribution Reliability Initiative, Rebuild Distribution Lines and Feeder Additions/Upgrades to Accommodate Growth.

For projects where it is not possible to determine the nature and scope of the work at the time the budget is prepared, budget estimates are based either on unit cost information derived from historical average expenditures, or on the basis of average historical costs adjusted for inflation.

Average historical unit costs provide a measure of transparency to the budgeting process. However, for unit costs to be an effective budgeting tool, two things are required: (1) a base with predictive value from which a unit cost can be derived; and (2) a means of forecasting changes to that base. Where information on which to base unit costs cannot be determined or where unit costs are of limited predictive value, budget estimates are based on average historical costs adjusted for inflation

The budget estimates for Extensions, Meters, *new* Services, and *new* Street Lights are based on average historical unit costs.

For *replacement* Services, as noted in the response to PUB 46.0 NP, the actual number of replacements is not tracked, and it is therefore not possible to derive the unit costs. For *replacement* Street Lights, as noted in the response to PUB 48.0 NP, the unit cost per replacement has no predictive value with respect to future replacement requirements. The budget estimates for these items are based on the arithmetic average of historical expenditures over the most recent 5-year period, adjusted for inflation. The budget estimates for the Transformers and Reconstruction projects are derived using the same method.

Unit Costs and Customer Growth
Prior to this year's capital budget process, Newfoundland Power based its expenditure projections for Extensions (and for *new* Services) on the expected number of gross new Domestic customer connections. Because of difficulties associated with the way General Service customer connections had been tracked historically, reliable data for new connections of General Service customers was not available. Gross new Domestic customer connection data was readily available, and provided a reasonable proxy for establishing unit costs.

In an effort to provide an improved basis for estimating budget requirements using unit costs, the Company implemented changes this year in its tracking of General Service customer connections. Those changes make it possible to track connections of General Service customers in *new* serviced premises separately from connections of General Service customers in *existing* premises. As a result, the Company was able to obtain a more accurate count of new connections for General Service customers. Further, by taking advantage of changes in the Customer Service System that had been implemented several years ago, it was also possible to obtain historical information on new General Service customer connections. With this better information, including restated historical unit cost information, the Company was able to base its unit cost calculations for the Extensions project, and for the *new* services component of the Services project on *total* new customer connections (Domestic and General Service).

The Difference Explained
The difference between the forecast number of 3,771 customers upon which the unit cost for 2005F shown in Table 2, page 26, Schedule B is based and the forecast number of 3,161 customers referenced in the *2005 Capital Expenditure Status Report* reflects the change in the method for deriving unit costs for the Extensions project as described above.

For consistency with the 2005 Capital Budget Application as filed, the explanation provided in the *2005 Capital Expenditure Status Report* is based on the number of gross new Domestic customer connections (3,161), which is the basis on which the 2005 budget estimate was derived.

The 3,771 new customer connections on which the forecast 2005 unit costs shown in Table 2, page 26, Schedule B are based include both Domestic and General Service customer connections.

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

PUB 44.0

Please provide new unit cost data for this capital item, including the unit cost data for 2005 as originally filed versus the current projected unit cost, and an explanation of the different (sic).

A. Table 1 below corresponds to Table 2, page 26, Schedule B of the Application, but restates the unit cost information for Extensions based on gross Domestic customer connections. Table 2, page 26, Schedule B provides unit cost information calculated on the basis of total new customer connections (both Domestic and General Service).

Table 1

Expenditure History and Unit Cost Projection

Year	**2001**	**2002**	**2003**	**2004**	**2005F**	**2006B**
Total Exp (000's)	**$5,404**	**$5,717**	**$6,586**	**$8,406**	**$7,396**	**$6,898**
Adjusted Exp (000's)	$6,116	$6,376	$7,126	$8,736	$7,396	-
Domestic Customers	2,306	2,773	3,022	3,530	3,161	2,845
Unit Cost ($/cust.)	2,652	2,299	2,358	2,475	2,340	2,425

The budget estimate of $6,898,000 derived using Domestic customer connections as a base, as shown in Table 1 above, corresponds to the 2006 capital budget estimate for Extensions of $6,766,000 shown in Table 2, page 26, Schedule B. The difference of $132,000 is the result of the change in the method of estimating the budget requirement described in the response to PUB 43.0 NP.

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

PUB 45.0

Please explain why the unit costs data for 2005 as originally filed, and the unit cost data for 2005 as currently forecast appear to be approximately 30% higher than the previous 5 year average.

A. It is assumed for the purpose of this response that the unit cost data for 2005 "as originally filed" refers to a unit cost of $2,590 derived from the original 2005 capital budget estimate for Extensions of $6,374,000 and the forecast of 2,461 new customer connections. As noted in the response to PUB 43.0 NP, the 2005 capital expenditure requirement for Extensions was estimated based on gross new Domestic customer connections.

It is assumed that the unit cost data for 2005 "as currently forecast" refers to a unit cost of $2,340 derived from the forecast 2005 capital expenditure for Extensions of $7,396,000 and the revised forecast of 3,161 new customer connections noted in the *2006 Capital Expenditure Status Report* at Appendix A, page 3 of 5. As noted in the response to PUB 43.0 NP, the revised forecast referred to in the *2006 Capital Expenditure Status Report* is also based on gross new Domestic customer connections.

It is assumed that the 5 year average unit cost referred to in the question is a unit cost of $1,958, which is the arithmetic average of the annual unit costs for the period 2001 to 2005F provided in Table 2, page 26 of 81, Schedule B.

As noted in the response to PUB 43.0 NP, the estimate of the 2006 capital expenditure requirement for Extensions is based on gross total customer connections, which includes new connections for *both* Domestic and General Service customers. In the interest of consistency, the historical unit costs set out in Table 2, page 26 of 81, Schedule B are restated unit costs derived from the new base of gross total customer connections.

The relatively lower 5 year average unit cost is the arithmetic result of calculating unit costs on the higher base of gross total customer connections, rather than on a base of gross Domestic customer connections.

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

PUB 46.0

<u>B-30 Services</u>
Why is there no unit cost data for "Replacement Services"?

A. Newfoundland Power does not track the actual number of services replaced. Without information on the number of units replaced, it is not possible to accurately calculate the unit cost of replacing a service.

Prior to 2006, Newfoundland Power projected expenditures associated with Replacement Services utilizing a unit cost based on the total number of customers served. With a customer base of over 200,000 that increases by approximately only 1% per year, this calculation produces a result that is not materially different than a simple arithmetic average of the cost over 5 years.

For the 2006 capital budget, the Company employed the more straightforward averaging approach. The requirement for Replacement Services was calculated as the average of the actual expenditures over the past five years adjusted as follows:

1) to remove expenditures associated with planned service replacements;
2) to account for inflation; and
3) to account for the forecast change in the customer base.

The result of the calculation based on the arithmetic average of annual expenditures on replacements is not materially different than the calculation based on the average unit cost per customer served.

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

PUB 47.0

B-30 Services

Please explain the 10% increase in the unit cost for "New Services" from 2004 to 2005.

A. As is evident in Table 2, page 31, Schedule B of the Application, the number of new customers connected to the electrical system can vary significantly from year to year. In 2003 and 2004, Newfoundland Power experienced significantly higher customer growth, principally in new residential subdivisions in the St. John's area.

The unit cost of new service connections in new residential subdivisions tends to be lower than average as a result of the economies of scale associated with higher density residential areas. For example, new services in higher density subdivisions generally require fewer service poles. Consequently, the higher proportion of urban residential subdivisions in the customer growth experienced in 2003 and 2004 resulted in relatively low unit costs in those years.

The 10% increase in the forecast unit cost for New Services in 2005 is due primarily to an expected decrease in the proportion of new customer connections in new subdivisions in the St. John's area, and a return to the more typical overall composition of new customer connections. In 2004, new residential customers in the St. John's area accounted for 50 per cent of total new customer growth. In 2005, the proportion is forecast to be reduced to 46 per cent.

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

PUB 48.0

<u>B-33 Street Lighting</u>

Why is there no unit cost data for "Replacement Street Lights"?

A. Although the actual number of street lights replaced could be determined without undue administrative effort, Newfoundland Power does not do so because the unit cost approach does not provide better predictive value for budgeting purposes than an approach using average historical costs.

Prior to 2006, Newfoundland Power projected expenditures associated with Replacement Street Lights utilizing a unit cost based on the total number of street lights in service. With a street light base of over 50,000 that increases by less than 1% per year, this calculation produces a result that is not materially different than a simple arithmetic average of the cost over 5 years.

For the 2006 capital budget, the Company employed the more straightforward averaging approach. The requirement for Replacement Street Lights was calculated as the average of the actual expenditures over the past five years adjusted as follows:

1) to remove expenditures associated with planned street light replacements;
2) to account for inflation; and
3) to account for the forecast change in the street light base.

The result of the calculation based on the arithmetic average of annual expenditures on replacements is not materially different than the calculation based on the average unit cost per street light in service.

Q. **DISTRIBUTION**

PUB 49.0

B-38 Reconstruction
What portion of the proposed expenditure of $2,849,000 is for labour (both internal and contractual)?

A. The proposed reconstruction expenditure for 2006 of $2,849,000 is comprised of $2,078,000 for labour and $771,000 for non-labour. Table 1 provides a complete breakdown of labour and non-labour amounts by cost category.

Table 1
2006
Reconstruction Expenditure
(000s)

Cost Category	**2006**
Labour	
Labour – Internal	1,147
Labour – Contract	643
Engineering	288
	$2,078
Non-Labour	
Material	674
Other	97
	$771
Total	**$2,849**

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

PUB 50.0

Did NP apply the GDP Deflator to the entire historical expenditures regardless of whether the expenditures were a mix of materials and labour? If so, please comment on the appropriateness of applying the GDP Deflator in this manner to generate estimates for future expenditures.

A. No, the GDP Deflator is applied to non-labour expenses only. This is consistent with Order No. P. U. 36 (1998-99) in which the Board ordered the adoption of the GDP Deflator for Canada as an appropriate inflation index to forecast non-labour operating expenses.

In the absence of a suitable deflator to adjust external labour costs, both internal and external labour costs are adjusted based on forecast annual changes in Newfoundland Power labour costs.

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

PUB 51.0

<u>B-41 Rebuild Distribution Lines</u>
According to Table 2 of B-41, in the past five years NP has expended approximately $17 million on rebuilds of existing feeder lines. NP is projecting future expenditures for 2006 to 2010 at $18.6 million.

<u>B-45 Distribution Reliability Initiative</u>
NP spent a total of $7.7 million in the previous five years (2001-2005F) on replacing specific distribution lines and is projecting a total future expenditure (2006-2010) of $7.2 million.

Accordingly, the total expenditures on distribution lines per B-41 and B-45 for the ten year period 2001 to 2010 is approximately $50 million. This works out to $165,562 per feeder (~$16,600 per year per feeder) or $6,100 per kilometer of line (~$610 per year per kilometer of line).

Are the above numbers (~$16,600 per year per feeder and $610 per year per kilometer of distribution line) useful measures of the expected unit costs for this category of expenditure?

A. The Rebuild Distribution Lines and Distribution Reliability Initiative budget items are planned projects for which the actual scope of work is determined by an engineering assessment of the observed condition of the relevant feeders. While it is desirable to levelize costs over time, the nature of the work associated with certain capital budget items presents limitations on the extent to which this is possible.

The noted projects are intended to deal with identified issues on specific feeders. The nature of this work tends to vary significantly from feeder to feeder.

For example, a significant issue identified with the BOT-01 feeder is accessibility. Consequently, much of the proposed work involves moving sections of line from more remote locations to the road right of way. The nature of the work proposed to be carried out on the BCV-02 feeder is different. Because the major identified issue is conductor failure, much of the proposed work involves re-conductoring sections of line.

Where the required work varies from feeder to feeder in this fashion, unit costs for each job will be different. Those differences can be substantial. As a result, unit costs based on historic averages for the budget category are not reliable indicators of actual expenditure requirements.

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

PUB 52.0

How do the figures in PUB-51.0 compare with the cost of constructing new distribution lines?

A. The figures referenced in PUB 51.0 NP pertain to the targeted repair and replacement of components of existing distribution lines to address identified concerns. This is fundamentally different in scope from the construction of a new distribution line.

The unit cost of $6,100 per kilometre of line referenced in PUB 51.0 NP is representative of the forecast average cost per kilometre of fixing specific problems in 2006 identified during feeder inspections and during normal operations.

The unit cost of constructing a new distribution line can range from $30,000 to $70,000 per kilometre depending on such factors as whether the line is a single phase or three phase line, whether the line voltage is 12.5 kV or 25 kV, and whether the route of the line is along a road or across country.

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

PUB 53.0

Please provide comparable numbers to those provided in PUB 51.0 for the construction of new distribution lines (B-48) showing the annual cost per kilometer and annual cost per feeder.

A. The capital budget project Feeder Additions and Upgrades to Accommodate Growth described at page 48 of Schedule B involves the upgrading of distribution feeders to accommodate customer growth and growth in the load requirements of existing customers. The required work will vary substantially from feeder to feeder, and from year to year, and may include new line construction, the re-conductoring of existing lines, or the installation of voltage regulators on existing lines.

Using historical expenditures for the past 5 years and forecast expenditures for the next five years, expenditures on Feeder Additions and Upgrades to Accommodate Growth over the 10-year period will approximate $264 per kilometre, or approximately $26 per kilometre per year (based on a total of 8,200 kilometres of distribution feeder lines). On a per feeder basis, the expenditures are $7,162 per feeder over the 10-year period, or approximately $716 per feeder per year (based on a total of 302 feeders).

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

PUB 54.0

<u>B-43 Relocate Distribution Lines for Third Parties</u>

Please provide the proposed capital expenditure for 2006 Net of the contributions expected from the customers making the requests.

A. The cost of relocating distribution lines for third parties in 2006 is estimated at $685,000. Contributions to be recovered from third parties in relation to the relocation of distribution lines at their request are estimated at $100,000. The estimated net expenditure for such relocations is therefore $585,000.

Requests for relocations are typically initiated by Aliant, cable television operators, the Department of Works, Services and Transportation or individual customers. In all cases, a contribution in aid of construction is determined in accordance with either a specific agreement with the third party, such as the Facilities Partnership Agreement with Aliant, or on the basis of cost less depreciation.

Much of the relocation work for Aliant and the cable television operators involves old, substandard plant that is either fully or substantially depreciated. Contributions are low relative to replacement cost, since they are based on the undepreciated value of the plant being replaced.

Additions to rate base on account of capital expenditures for the relocation of distribution lines are net of the required contributions of those requesting the relocations.

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

Information Systems

PUB 55.0

Please provide the total capital expenditures proposed for 2006 which are directly related to making improvements and enhancements to NP's Customer Service System.

A. The capital expenditures proposed for 2006 which are directly related to making specific improvements and enhancements to the Customer Service System ("CSS") are found in the Group Bill Enhancements and the Customer Tracking and Setup Improvements budget items described at pp. 2 – 3 of *6.1 2006 Application Enhancements*. These proposed expenditures total $244,000.

The Remote Agent Enhancements and Predictive Dialer budget items included under the heading Customer Service Systems Enhancements in *6.1 2006 Application Enhancements* will be used by the Company's customer service personnel in conjunction with the CSS. However, they are not direct enhancements to the CSS itself.

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

Information Systems

PUB 56.0

Has the status of the expected migration of the CSS from OpenVMS (discussed at p 15 of the 2006 Capital Budget Plan) changed?

A. The status of the expected migration of the CSS from OpenVMS has not changed. The Company continues to monitor the suppliers' strategies and future support for OpenVMS through ongoing contact with suppliers and industry experts such as Gartner Group.

There have been no significant announcements of changes in technology plans relevant to the OpenVMS issue since the *CSS Replacement Analysis Report*, dated July 16, 2003, was filed with the Board as part of the Company's 2004 Capital Budget Application.

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

Information Systems

PUB 57.0

Under the status as currently understood by NP, when will the Company need to seek approval for the migration of the CSS?

A. The timing of an application to the Board for approval of capital expenditures associated with the replacement or technical migration of the CSS would need to accommodate a lead time of up to 24 months. This is the amount of time that would be required to implement either of the options identified in the *CSS Replacement Analysis Report*, dated July 16, 2003, filed with the Board as part of the Company's 2004 Capital Budget Application.

As noted in that report, the Company envisions a re-examination of the continued viability of the CSS in 2006.

Q. **<u>LEASES</u>**

PUB 58.0

C-2 Production Printers
Has NP conducted a lease versus purchase analysis, and if so, why is it not included as part of the justification for the project?

A. A lease versus purchase analysis was not conducted for the production printers prior to the filing of the Application. Because the Company's recent history with the acquisition of printers has typically favoured the leasing option, it was considered appropriate to present the leasing option in the Application as the most likely scenario.

A lease/buy analysis is always conducted before acquisition where those options are appropriate considerations. However, conducting such an analysis as many as 12 months in advance of an acquisition may be premature, given the potential for changes in printer technology and in financial markets over time.

If, at the time of acquisition, the lease/buy analysis favours a purchase, the Board will be apprised of the change.