# NEWFOUNDLAND AND LABRADOR HYDRO
# BEFORE THE
# BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

# EVIDENCE OF EES CONSULTING ON COST OF SERVICE AND RATES

**September 2, 2003**

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**EXHIBITS**

# 1 Introduction and Summary of Recommendations

This evidence is being presented on behalf of the Public Utilities Board of Newfoundland and Labrador (Board), in response to evidence submitted by Newfoundland and Labrador Hydro (Hydro). Gail Tabone and Nigel Chymko are Vice Presidents with EES Consulting and their resumes are provided as Exhibits A and B, respectively.

EES Consulting reviewed the Cost of Service (COS) methodology and model used by Hydro in support of their application, and examined the rate design resulting from the COS analysis. To that end, this evidence addresses certain items related to the COS methodology and rate design that were found to warrant further study. The goal of this evidence is to comment and question some of the methods used by Hydro as well as to provide to the Board examples of standard practices regarding these issues.

The topics to be addressed in this evidence include:

- Generation Classification
- Distribution Classification
- Distribution Allocation
- Labrador Interconnected System
- GNP, Doyles-Port aux Basque & Burin Peninsula Assignment
- Other changes from the Last COS
- Newfoundland Power Rate Design

## 1.1 Background and Objectives

The setting of utility rates that are fair, just and reasonable is guided by generally accepted industry and rate setting principles. In general, the application filed by Hydro follows these guiding principles and complies with the general guidelines found in the Board's 1993 generic COS report and the June 7, 2002 Order P.U. 7. However, the process of setting rates is a highly subjective issue and there exist many different and acceptable methods, which functionalize, classify and allocate costs to consumers. The difficult part of a COS is to determine the appropriate method to use for the specific systems evaluated. On the rate design side, there is often a large amount of judgment used and factors outside of pure costs come into play.

The geography of Labrador and Newfoundland requires Hydro to be a combination of Isolated and Interconnected systems. In Labrador, an interconnected system sharing generation and transmission facilities is located to the south, while numerous isolated communities are located along the coastline. On the Island, the interconnected system covers most of the island, including Newfoundland Power's service area, while a few isolated systems with their own generation are located along the coast as well. Hydro sells generation and transmission to Newfoundland Power (NP), who in turn gets credit for NP owned generation capacity in the COS.

## 1.2 Summary of EES Consulting Recommendations

The main issues that EES Consulting wants to address in this evidence are mostly issues that have been discussed in previous rate cases. However, due to the controversial aspect of these issues, they do warrant additional consideration by the Board. The following lists the issues and the EES Consulting recommended changes to the COS and Rates Application filed by Hydro. Some of these will require a change in the approach previously approved by the Board in P.U. 7.

- Generation plant should be classified using the Peak Credit method rather than the Load Factor method.
- Distribution plant should be classified to demand and customer based on a minimum system analysis, not a zero-intercept analysis. Hydro should develop the appropriate data to perform a minimum system analysis in future filings.
- Distribution Allocation should be performed using NCP rather than CP.
- The Labrador Interconnected System should remain an interconnected system in the COS. There is no compelling evidence that the system is not interconnected.
- GNP, Doyles-Port aux Basque & Burin Peninsula Assignments should use a consistent assignment methodology for the generating and transmission facilities. A detailed study has found great benefit to all customers on the Island Interconnected System from the generating resources and therefore assigned these resources as common. The methodology used to assign the associated transmission facilities should be similar. The common system cannot get the benefit of the generation resources without the transmission facilities.
- Hydro Place Systemization as proposed should be adopted
- General Plant functionalization as proposed should be adopted
- Taxes and Board Assessment Functionalization & Classification as proposed should be adopted
- The Newfoundland Power wholesale rate should include a demand charge with a ratcheted billing determinant.

The impacts associated with the recommended changes, to the extent they could be quantified with the data available to us, are summarized in Table 1. Based on our recommendations, the residential consumers within the two interconnected systems would benefit while the commercial and industrial customers would see an increase in costs. For the isolated systems, the residential customers would see an increase in costs, with the commercial customers seeing a significant decrease. Newfoundland Power would also see a slight savings due to the recommendations.

**Table 1**
**Revenue Requirement Impacts Due to Change to Peak Credit, NCP and Minimum System Method**

| System | Residential | Commercial | Industrial | Newfoundland Power |
|---|---|---|---|---|
| Island Interconnected | -1.2% | 2.0% | 2.8% | -0.6% |
| Island Isolated | 3.7% | -9.6% | 0.0% | N/A |
| Labrador Isolated | 4.9% | -7.6% | 0.0% | N/A |
| L'Anse au Loup | -0.8% | 1.5% | 0.0% | N/A |
| Labrador Interconnected | -2.6% | 3.2% | 0.0% | N/A |
| Total | 0.3% | -1.1% | 2.8% | -0.6% |

# 2 Generation Classification

## 2.1 Introduction

For generation, Hydro has proposed a method where the load factor for either the system in question or the individual power plant is used to classify costs between demand and energy components. For the Labrador and Island isolated systems this results in approximately 16 percent and 29 percent, respectively, classified as demand. For the Labrador Interconnected system, approximately 48 percent is classified as demand, while 19 percent is allocated to demand for the Island Interconnected System. While the Board has confirmed this method in the past, it is inconsistent with the practice of most other electric utilities that we have experience with. For that reason, and others, we recommend the consideration of alternative methods.

In addition to the load factor method proposed, common generation classification techniques include:

- Fixed/Variable Method
- Base/Intermediate/Peak Method
- Peak Credit Method

The following is a brief description of each method:

Under the Fixed Variable Method those costs that are fixed in nature are classified as demand-related. This includes depreciation, return on rate base and taxes. Variable costs are classified as energy. This includes fuel and O&M expenses.

The Base/Intermediate/Peak Method separates resources into the place within the resource stack, with base load units classified as energy-related and peaking units classified as demand-related. Intermediate units would be split between demand and energy.

The Peak Credit Method looks at the cost of a unit built only to meet peaking needs. Generally this would be a simple cycle gas turbine or diesel generator. The peak credit method estimates the proportion of costs that are demand related by dividing the cost of a proxy capacity resource by a proxy base load resource.

## 2.2 Background

Before making a recommendation, it is important to consider the history of generation treatment in the Province, precedents in other jurisdictions, the specific circumstances of the system, and the impacts of a change in the methodology.

In 1993, the generic COS report discussed the classification of generation plant in great detail. Numerous methods were discussed and proposed both for hydraulic facilities and thermal facilities. In general, all participants agreed that all plant costs relating to gas turbines and diesel generation in the Island Interconnected system should be classified 100 percent demand related. These plants serve peaking and reserve capacity and this type of classification was deemed reasonable.

For hydroelectric generation, proposed classification methods included specific facilities, equivalent peaker, fixed/variable, dependable capacity, peaker credit and plant factor methods. The classification of costs to the demand component ranged from 18 to 97 percent.

The methods proposed to classify Holyrood plant costs included 100 percent demand (with Average and Excess allocation), peak credit, plant factor methods and equivalent peaker methods. Again, the range in costs classified to demand was large.

Various parties discussed numerous issues with the equivalent peaker method. The main issue addressed by the Board was the process of determining a value of the peaker unit. The Board stated that using the "cost of gas turbines of approximately the same vintage as other major plant acquisitions are likely to be more trust worthy than present-day costs". However, the Board also stated that it "would not necessarily make it equitable for electricity users in 1993 to pay for energy what planners one or two decades earlier thought it would cost to produce energy in 1993". The Board concluded that the equivalent peaker method may provide a useful indication, but it should not be used as the sole method for generation classification.

Because the purpose of the generation resources is to serve customer loads, the Board concluded that the system load factor should be used for hydraulic generation and 5-year average plant load factor should be used for Holyrood. They concluded this methodology would ensure that as the load factor of the system changes, the costs classified to energy and demand would adjust as well. Holyrood is the marginal resource and operates at a low capacity factor. By using the plant-specific capacity factor, the Board concluded that costs would be classified in an appropriate manner as output changes.

The most recent Order for Hydro's COS was dated June 7, 2002. The Order provided by the Board in 2002 is consistent with the precedent set in 1993 when the Board made its initial ruling on Hydro's COS approach. In fact, the Board in this order only addresses issues that were not addressed or finalized in the 1993 generic COS. The 2002 Order only addresses classification of hydraulic plants due to an objection by the Industrial Customers of how Hydro calculated the annual system load factor. The Board, in this order, confirms Hydro's treatment for classification of hydraulic plants to be in accordance with the 1993 generic COS methodology.

## 2.3 Discussion

While the precedent for Hydro is based on the load factor method, this is not the most common approach used today in ratemaking in North America. In fact, in Alberta and Ontario, where the market has been deregulated, there is no need to classify generation costs and a market for demand and energy components has developed. Historically, Alberta used the fixed/variable method. In British Columbia plants are classified as to whether they were built to meet demand or energy needs.

From a theoretical basis, the load factor method is simplistic as well as dated in its use. The base/intermediate/peak method has a sound theoretical rationale but is less widely used and is difficult to implement for a system with a limited mix of resources. In the case of Hydro the majority of systems only have one resource that meets all of the power supply needs.

The peak credit is most theoretically correct in our opinion, as it accounts for what type of costs would be incurred to serve the demand component alone. It is also widely used and is representative of what occurs in market prices in those jurisdictions where there is ample competition on a wholesale basis.

Generally the demand-related component within the peak credit method is based on the use of a gas-fired simple-cycle combustion turbine (SCCT). This is the resource of choice for new peaking units when gas is readily available. Gas is currently available for generation within both the Island and the Labrador Interconnected systems and thus the peak credit method will work well to classify the costs of the hydropower, diesel units and contracts in these areas.

For the isolated systems that have only diesel generation, a gas-fired SCCT is not a viable option. In those regions a diesel unit would be the logical choice for a peaking plant. For that reason, the fixed/variable method is basically the same as the peak credit method because the capital cost of the existing units would be the same as the cost of a peaking unit. For meeting peak needs alone, the capital cost is sufficient with a negligible amount of O&M and fuel. Generally, the fuel used throughout the year, as well as the O&M expense, is a function of the amount of energy generated.

## 2.4 Impacts

To determine the impacts within the COS associated with changing the model for generation classification, we classified costs using the Peak Credit method. The Peak Credit method assumed generation plant and fuel costs previously classified based on the Load Factor method would be classified 22 percent demand and 78 percent energy. Purchased power, except for contracts for the Isolated systems, were also classified 22 percent demand and 78 percent energy. For the Isolated systems, plant was classified 100 percent demand. Fuel & purchased power were classified 100 energy. In these systems the purchased power is small and provide primarily energy and were not necessarily implemented to provide planned capacity. Table 2 provides the results of the classification for each system while Table 3 shows the impacts by customer class for each system.

**Table 2**
**Comparison of Classification of Generation Costs**

| System | Current Load Factor Method (Percent Demand-Related) | Proposed Peak Credit Method (Percent Demand-Related) |
|---|---|---|
| Island Interconnected | 19% | 22% |
| Island Isolated | 29% | 64% |
| Labrador Isolated | 16% | 44% |
| L'Anse au Loup | 27% | 28% |
| Labrador Interconnected | 48% | 21% |
| Total | 29% | 64% |

**Table 3**
**Impacts by Customer Class Due to Change to Peak Credit Method**

| System | Residential | Commercial | Industrial | Newfoundland Power |
|---|---|---|---|---|
| Island Interconnected | -0.5% | 0.3% | 3.8% | -0.8% |
| Island Isolated | 4.3% | -11.4% | 0.0% | N/A |
| Labrador Isolated | 6.4% | -9.8% | 0.0% | N/A |
| L'Anse au Loup | 0.0% | 0.0% | 0.0% | N/A |
| Labrador Interconnected | -2.1% | 1.5% | 3.4% | N/A |
| Total | 1.1% | -2.9% | 3.7% | -0.8% |

The work papers associated with Table 2 and Table 3 can be found in Exhibit C.

## 2.5 EES Consulting Recommendation

Given the appropriateness of the theory, the precedents in other jurisdictions, the applicability to Hydro's own mix of resources, and the impacts associated with a change, it is our recommendation that the Peak Credit method be used. For the Interconnected Systems, this method would assign 22 percent of fixed generation costs as demand-related. Fuel would be 100 percent assigned to energy. For the isolated systems, 100 percent of generation plant costs would be assigned to the demand function as the diesel units are virtually the same option that would be installed for peaking only. Fuel and purchased power would be classified as 100 percent energy.

# 3 Distribution Classification

## 3.1 Introduction

Hydro has used the zero-intercept method to classify distribution plant, consistent with the Board's last rate order. This method splits costs between demand and customer components based on the fact that a theoretical system with zero-sized poles, etc. would be used to serve customers regardless of the amount of load they placed on the system. The remaining amount is demand-related as any size above that theoretical system is based on the need to meet peak loads.

Alternative methods of distribution classification are:

- 100 percent Demand-related
- Minimum System
- Demand/Energy Split

The following provides a brief description of each method. For all of these methods, not all distribution accounts are treated the same. Generally substation accounts are 100 percent demand-related due to sizing of the facility to meet peak loads and meters and services are generally 100 percent customer-related since they need to be installed at each customer location, regardless of size. The variability in methods comes into play for the transformers, poles and conduit.

Classifying 100 percent of distribution costs to the demand function is based on the theory that distribution facilities are generally sized to meet the peak demand of the customers served by the facility. Since this approach does not classify any costs to customers, this is beneficial for the small users.

The minimum system approach is similar to the zero intercept approach in theory. Costs are split between demand and customer due to the fact that some minimum system would be needed to serve customers regardless of their load level. In this case, however, the minimum size of each piece of equipment is used rather than the "zero-sized" level. For example, a 30- foot pole might be the smallest size commercially available. In that case the costs for an entire system of 30-foot poles would be customer-related and the cost for installed poles larger than that would be demand-related. This approach classifies a larger portion of costs to the customer component than the zero-intercept method and is therefore favourable for large customers.

Finally, splitting costs between demand and energy is based on the theory that the distribution system is used to meet both the demand and energy needs of the customer. A sharing of costs under this approach is the most beneficial to small users of the various methods considered.

## 3.2 Background

Hydro's proposed zero-intercept method is the same methodology that was proposed and approved in 1993 and 2002. In 1993, the Board approved this methodology, but it was reluctant to recommend this approach for the long-term and ordered Hydro to revise the study for the next rate hearing. The only comment received by Intervenors on this issue in 1993 was from the Board's expert. He believed that the zero-intercept method results in too high customer costs. However, he conceded that the methodology does not have a great impact on cost sharing between customers.

In 2002, once again, only the Board expert provided comments on the use of the zero-intercept method. Mr. Wilson did not believe that this method classifies costs between customer and demand in a correct manner. Hydro did state that there were data limitations, which precluded Hydro to perform a minimum system study. The Board fount that no other parties contested the methodology and that there was not sufficient evidence on record to reject the methodology. The Board therefore approved the use of the zero-intercept methodology as proposed by Hydro.

In 2002, Hydro confirmed that most integrated utilities in North America rely on minimum system rather than zero-intercept. In addition, most utilities in Canada use some form of minimum system analysis as well (From NP Witness Brockman p. 9).

## 3.3 Discussion

When examining the current zero-intercept analysis for poles performed by Hydro, it was found that the customer component was increased from 33.6 percent in the earlier study to 54.3 percent in the current study. The reason for the increase in the customer component is that Hydro did not increase the cost of the poles in the updated analysis, but only increased the cost of installation. Since the cost of installing poles does not differ between the diameter sizes, the slope does not change and the line is just shifted upwards, thereby increasing the zero intercept. The large difference in results between the two studies does not demonstrate a robust analysis, however, the current zero-intercept study provide results much closer to the ones likely to be seen with a minimum system analysis.

Given the theoretical consideration, we believe the minimum system method is the most appropriate. It recognizes that any customer, regardless of size, is going to cause a certain level of distribution system to be built. While the zero-intercept approach shares this general philosophy, it requires the assumption that there is such a thing as a "zero-sized" system. It also has a potential problem that the zero-sized facility could result in a negative cost outcome. The minimum system is also the most widely accepted method across Canada, it is consistent with the method most recently approved for NP by the Board and is the method we generally use when developing COS studies for other clients.

## 3.4 Impacts

The results of the zero-intercept method are shown in Table 4, along with our initial estimation of the minimum system approach using NP's 2001 analysis as a proxy. Details associated with our calculations can be found in Exhibit D.

**Table 4**
**Comparison of Zero-Intercept and Minimum System Methods based on NP's 2001 study**

| Distribution Account | Zero-Intercept Customer % | Zero-Intercept Demand % | Min. System Customer % | Min. System Demand % |
|---|---|---|---|---|
| Substations | | 100.0% | | 100.0% |
| Poles, Towers, Fixtures | 32.0% | 68.0% | 41.1% | 58.9% |
| Overhead Conduit | 11.3% | 88.7% | 15.7% | 84.3% |
| Transformers | 63.9% | 36.1% | 27.0% | 73.0% |
| Services | 100.0% | | 100.0% | |
| Meters | 100.0% | | 100.0% | |

Given the switch to a minimum system approach, using the current NP calculated factors, the following results show the impact on the cost of service results.

**Table 5**
**Impacts by Customer Class Due to Change to Minimum System Method**

| System | Residential | Commercial | Industrial | Other |
|---|---|---|---|---|
| Island Interconnected | 0.2% | -0.5% | 0.0% | 1.1% |
| Island Isolated | 0.0% | 0.0% | 0.0% | 0.2% |
| Labrador Isolated | 0.1% | -0.1% | 0.0% | 0.4% |
| L'Anse au Loup | 0.2% | -0.6% | 0.0% | 2.5% |
| Labrador Interconnected | -0.4% | 0.9% | 0.0% | -2.4% |
| Total | 0.1% | -0.2% | 0.0% | 0.5% |

## 3.5 EES Consulting Recommendation

Given the theory behind the various methods and associated precedents, we support the minimum system approach. We recommend that the Board should consider directing Hydro to prepare an updated minimum system study using more current data for future rate hearings. For the present time, the impacts associated with the use of NP's minimum system factors are quite small and therefore we do not believe it is necessary to make the adjustments in the COS at this time.

# 4 Distribution Allocation

## 4.1 Introduction and Background

For the portion of distribution costs classified as demand-related, Hydro has proposed to use the single coincident peak (CP) factor to allocate those costs between customer classes. This is consistent with the most recent Board order and according to Hydro was "done in recognition of the fact that Hydro plans its facilities on the aggregate distribution system load."

It is much more standard for distribution costs to be allocated on the basis of the non-coincident peak (NCP) rather than the CP. In 2001 Dr. Wilson provided a good summary of the theory behind the use of NCP rather than CP (See Exhibit E).

Both the Board expert and CA raised a question regarding the use of CP to allocate distribution demand costs and proposed that NCP should be used instead. Hydro countered that since NP and IC are not allocated distribution costs, the allocation factor used only effects Island Interconnected Rural Customers, Isolated Rural Customers and Labrador Interconnected customers. Rates for the Island Interconnected Rural Customers were not determined in the COS and the allocation factor does therefore not affect these customers. In the rural isolated systems, the distribution systems are sized based on anticipated peak, which according to Hydro supports the use of CP. On the Labrador Interconnected system, the distribution system is sized to meet the cold-weather peak, which also supports the use of CP.

## 4.2 Discussion

While we strongly support the use of the NCP factor, it has been argued by others that there is not a significant difference between the CP and the NCP for the isolated systems. For a small isolated community there may only be one substation, for example, and planning for that substation would be based on the load to be placed on the substation, which would be the sum of the maximum load placed by various customer classes. In this case the sum of the maximum loads would set the system peak and therefore the NCP would be the same as the system CP.

For the Island and Labrador Interconnected Systems, there is a large geographic area served. Expanding upon the substation example, there would be many substations installed within that large area; within the area, the substations may be connected to each other. In this case, each substation would be sized to meet the peak load of the surrounding local areas. When you add up the peak load of each separate area (the NCP), it would likely be greater than the CP for the Interconnected system due to the diversity in loads.

## 4.3 Impacts

Based on data provided in the load file of the COS model, the difference between CP and NCP for the five systems are in the range of 18 to 59 percent. As expected, the difference between the CP and NCP is less for the isolated systems than for the Interconnected Systems, but in both cases there is a measurable difference.

**Table 6**
**Comparison of Primary CP and NCP**

| System | CP (kW) | NCP (kW) | Percent Difference |
|---|---|---|---|
| Island Interconnected | 81,345 | 99,372 | 22.2% |
| Island Isolated | 2,122 | 2,779 | 31.0% |
| Labrador Isolated | 7,409 | 11,791 | 59.1% |
| L'Anse au Loup | 3,570 | 4,229 | 18.5% |
| Labrador Interconnected | 106,623 | 127,050 | 19.2% |
| Total | 201,068 | 245,221 | 22.0% |

**Table 7**
**Comparison of Secondary CP and NCP**

| System | CP (kW) | NCP (kW) | Percent Difference |
|---|---|---|---|
| Island Interconnected | 72,236 | 87,735 | 21.5% |
| Island Isolated | 2,003 | 2,623 | 31.0% |
| Labrador Isolated | 6,952 | 11,063 | 59.1% |
| L'Anse au Loup | 3,220 | 3,815 | 18.5% |
| Labrador Interconnected | 96,484 | 114,569 | 18.7% |
| Total | 180,895 | 219,806 | 21.5% |

Given the switch from a CP to and NCP approach, the following results show the impact on the cost of service results.

**Table 8**
**Impacts by Customer Class Due to Change to Minimum System Method**

| System | Residential | Commercial | Industrial & NP | Other |
|---|---|---|---|---|
| Island Interconnected | -1.1% | 2.5% | 0.0% | -1.8% |
| Island Isolated | -0.7% | 2.0% | 0.0% | -1.1% |
| Labrador Isolated | -1.7% | 2.6% | 0.0% | -1.9% |
| L'Anse au Loup | -1.1% | 2.3% | 0.0% | -2.0% |
| Labrador Interconnected | -0.6% | 1.1% | 0.0% | -0.5% |
| Total | -1.1% | 2.3% | 0.0% | -1.6% |

## 4.4 EES Consulting Recommendation

Because the NCP method is more theoretically sound and is more widely used, we suggest that the NCP be used to allocate demand-related distribution costs. The difference between the CP and NCP is measurable and the impacts to customer classes are sufficient to warrant the change.

# 5 Labrador Interconnected System

## 5.1 Introduction and Background

The Labrador Interconnected system consists of customers in the Happy Valley/Goose Bay, Labrador City and Wabush areas. In the past two rate hearings, Labrador City and Wabush (Labrador West) have objected to a single COS for the Labrador Interconnected System for the purpose of setting rates for Labrador West. The objection was that the interconnected system "consists of two discrete systems, one in the Happy Valley/Goose Bay area and one in the Labrador West area, with respective systems having different histories, dealing in different economies and different cost bases."

Both areas receive power supply from Hydro through a single contract with CF(L)Co and power generated at Churchill Falls. It is Hydro's position that since the customers are served from the same generation source, they are part of an interconnected system and should pay the same rates.

Labrador City's Witness in the 2001 hearing stated that while generation and transmission may be common for the Labrador Interconnected System, distribution costs for Labrador City and Wabush are lower than for the remaining Interconnected System. Hydro purchased these distribution systems at no cost and while additional investments have been made, Labrador City maintains that the overall distribution costs allocated to these cities should be much lower than resulting from the COS analysis. Based on calculations in 2001, Labrador City's share of distribution facilities is approximately 20 percent, while the share of load is approximately 40 percent of the total Labrador Interconnected System.

The Board in both the 1993 Generic COS Report and the 2002 Order discussed this issue. The Board, in both cases, did not find sufficient evidence to change the methodology proposed by Hydro and found that a single COS study is appropriate for Labrador Interconnected System.

## 5.2 Discussion

It is our position that the communities in Labrador receiving supply from Churchill Falls constitute an interconnected system and should not be separated into multiple systems or COS analyses. The Labrador Interconnected system is more like the Island Interconnected system than like any of the Isolated systems. Generation facilities are shared, some transmission facilities are shared, and while the distribution systems are separate, this is the case in most of the rural service areas. Numerous jurisdictions with larger service areas than Hydro (for example: BC Hydro, Nova Scotia, Manitoba Hydro, Hydro Quebec, ATCO Electric) have a single rate by customer class for the full interconnected system, even though the actual costs may vary by location. Postage stamp rates are standard practice for distribution utilities in order to ensure fair, equitable and stable rates. If rates are set on a city by city basis, large capital expenditures required to maintain the system are likely to hit hard in a small community and can cause significant rate volatility. With a single interconnected system, all customers benefit from the ability to smooth capital expenditures across different areas over time.

In addition, the original purchase price does not denote the value of a system and should not enter into the cost of service analysis. The purchase price of the Labrador City system was $1, because that was the value to the seller at the time. It does not mean that this sales price is the value of the system to the community.

## 5.3 EES Consulting Recommendation

Based on a review of the facts in this case, we do not see sufficient evidence to show that the Labrador system is not interconnected. We recommend that there continue to be a single COS for the Labrador Interconnected System and that rates are the same within the system, regardless of the location of the customer.

# 6 GNP, Doyles-Port Aux Basque & Burin Peninsula Assignments

## 6.1 Introduction and Background

Some costs are directly assigned to a specific customer class based upon the unique characteristics of the costs. As such, the traditional functionalization, classification and allocation methods are not required to allocate those costs to each customer class. Hydro owns facilities in three areas on the Island Interconnected system that have been examined for the purpose of specific assignment.

In the 2002 Order, GNP generation and transmission assets were assigned to Hydro rural, while the Doyles-Port aux Basque area transmission facilities were directly assigned to NP. The facilities on the Burin Peninsula were assigned common. Hydro was also ordered to examine the value of the Burin Peninsula, the Doyles-Port aux Basque and GNP systems to the grid for the next rate hearing. The Board has stated in the past "Transmission dedicated to serve one customer should be specifically assigned and costs of substantial benefit to more than one customer should be apportioned among all customers". The Board also addressed the inherent inconsistency in the assigning generation and transmission differently.

The current COS files assigns all generation and transmission facilities as ordered by the Board in Hydro's last rate hearing. However, the study undertaken as a result of the 2002 Order suggests that the GNP generation should be assigned as common, the transmission facilities on GNP and Doyles-Port Aux Basque should be specifically assigned and the Burin transmission facilities should be assigned as common.

Hydro therefore proposes that the GNP transmission assets will be assigned Hydro rural, because the transmission system was constructed to benefit customers in these remote areas. The GNP generation resource was initially built to serve the peninsula only, Hydro reasons, but because of transmission interconnection, the generation resource can provide benefit to the total interconnected system.

The issue at Doyles-Port aux Basque is similar to the GNP transmission resource, according to the report. Hydro states, that the transmission facilities were built to serve customers in the area, and while Hydro pays NP revenue credits for the resource (because of benefits to the Inter-connected system), the transmission assets are deep within NP's service area and should be specifically assigned to NP.

The Burin Peninsula resource (owned by NP) serves both Hydro and NP customers. The transmission facilities are used by generation resources owned both by NP and Hydro and serve customers on both systems. Therefore, it is Hydro's opinion that the transmission facilities should be assigned common.

## 6.2 Discussion

It is EES Consulting's opinion that generation facilities and the associated transmission facilities should be assigned in a similar manner. The theory is that the transmission system is essentially an extension of the production system and that the benefits of the production facilities cannot be delivered without the associated transmission facilities. In general any transmission facilities that are part of an integral system are assigned common.

Only in rare cases where a radial line clearly cannot be used by any other customer class, should it be direct assigned. Direct assignment of these radial lines is the subject of much debate. If the facilities truly are not integrated, reliability will likely be lower than on the integrated system. On the other hand, costs may be as high or higher for service due to the direct assignment of costs. Because of this, utilities, that direct assign facilities, must have irrefutable evidence of the independence of the facilities directly assigned.

## 6.3 EES Consulting Recommendation

Hydro has not provided a clear case for directly assigning transmission facilities in the GNP and Doyles-Port aux Basque areas. The generation resources at GNP and Doyles-Port aux Basque cannot provide service without the associated transmission facilities. Given that all customers on the Island Interconnected System benefits from the resources in the three areas mentioned, and given that the benefit would not occur if the transmission facilities were unavailable, it is our recommendation that the transmission facilities be allocated in the same manner as the generation resources: as common facilities.

# 7 Changes From Last Filed COS

## 7.1 Background and Discussion

This section will discuss the additional changes from the last COS model filed with the Board. There are three areas that will be discussed: Hydro Place assignment, General Plant functionalization, and Municipal taxes & Board assessment.

The first step in the Hydro COS is to separate costs into the 5 systems. In the previous COS filed, Hydro separated costs based on location. However, in the most recent filing, the costs associated with Hydro Place were assigned to all 5 systems rather than to the Island Interconnected System. The reason for this change, according to Hydro, is that Hydro Place provides administrative support to all systems.

General plant functionalization was also modified in this COS. Previously, general plant was functionalized as all other plant according to Hydro's filing. In this study, expenses were used to functionalize general plant between generation, transmission, distribution and customer functions. The expense method used by Hydro assumes that expenses consist mainly of labour and they are therefore a proxy for labour ratios, which is a common approach used across North America.

Finally, Hydro also changed the functionalization and classification of municipal taxes and the Board assessment in this COS as well. In the current COS, these costs are functionalized and classified as revenue and then later allocated to customer classes based on all other non-revenue related costs. This methodology ensures that revenue related costs are allocated to customer classes based on the current COS analysis.

## 7.2 Recommendation

In general, we recommend adoption of the changes proposed by Hydro regarding the above issues. Based on the guiding principle of setting rates that reflect cost causation, it is EES Consulting's opinion that allocating Hydro Place costs to all systems does appear appropriate. In addition, the methodology proposed by Hydro to functionalize general plant also appears as an appropriate method to functionalize general plant. Finally, based on EES Consulting experience, the methodology used to functionalization and classification of municipal taxes and the Board assessment appears appropriate. Taxes are clearly revenue related and should be allocated based on revenue. Existing regulatory costs, or Board assessment, are also appropriate to include in the revenue requirement.

# 8 Rate Design for Newfoundland Power

## 8.1 Introduction

The Board directed Hydro, on page 150 of P.U. 7, to file evidence related a demand-based tariff to be charged to NP. Consequently, Hydro filed as part of its 2004 application a study by Stone & Webster Management Consultants Inc. ("SWMCI") that recommends a demand-based rate structure for the NP tariff. However, on page 3 of the Rates and Customer Services section of the application, Hydro proposes to continue charging an energy only rate to NP, pending resolution of a number of issues:

- The degree of risk to be assumed by Hydro
- An appropriate weather normalization methodology
- The treatment of NP generation
- Appropriate costing and billing determinants

Subsequent Requests for Information (RFIs) to Hydro attempted to obtain further clarification of Hydro's proposal. In its response to CA-131, Hydro states that it is adopting the recommendations of this study as part of its 2004 application in the belief that certain issues, generally around the calculation of billing determinants, can be resolved prior to or as part of this hearing. As a follow up to CA-131, Hydro responds to CA-203 by stating unequivocally that it is proposing to implement this rate for January 1, 2004. In its response to PUB-150, Hydro implies that it is adopting the recommendations of the SWMCI study on the condition that Hydro risk "is limited to two percent of its forecast demand costs". This point is repeated again in Hydro's response to NP-178.

In PUB-150, Hydro clarifies the proposed demand based rate. Table 9 shows both the current and proposed rate for NP.

**Table 9**
**Current and Proposed Rate for NP**

| | Demand Charge | Energy Charge (First 420 GWh) | Energy Charge (All Over 420 GWh) |
|---|---|---|---|
| Current Rate (Sept '02) | N/A | $0.04789 / kWh | $0.04789 / kWh |
| Proposed Rate (PUB-150) | $7.00/kW-month | $0.03484 / kWh | $0.04700 / kWh |

Also in PUB-150, Hydro further clarifies that the proposed demand charge of $7.00 per kW-month is based on the demand related costs allocated to NP in the cost of service study. On a unit-cost basis, excluding allocated rural deficit costs and revenue credits, NP's allocated demand related costs are $7.04 per kW-month. On page 12, SWMCI notes that customer-related costs allocated to NP are less than one percent of NP's cost of service and suggests that Hydro "may wish to simply include these costs in the energy component of the rate". In its response to NP-126, Hydro confirms that the energy component of the proposed NP rate does include recovery for customer related costs.

Hydro's response to PUB-150 also confirms that it proposes to adopt SWMCI recommendations regarding the calculation of NP's peak demand billing determinant ("billing demand"). From January to March, billing demand is based on "the highest Native load less generation credits beginning in the previous November and ending in the current month". For the remaining months, billing demand is based on "Weather-Adjusted Native Load less generation credits, plus the Weather Adjustment True-up" (page 16 of SWMCI report). In both seasons, the minimum billing demand is set at 930.1 MW, which is 98 percent of NP's 2002 Native Load less generation credits (see response to PUB-182). This billing demand calculation involves two features that have a material impact on the amount charged to NP:

- Weather normalization: A stated objective of the SWMCI study is to design a rate that will avoid "a windfall or penalty to either utility due to abnormal weather" (page 3). Therefore, Hydro's proposed rate relies upon weather adjusted billing demand in most months.
- Generation credits: A stated objective of the SWMCI study is to design a rate that will "rationalize the rate approach with the treatment of NP's generation in the COS" (page 3). NP's generation resources become an issue in this regard because some of these generating facilities are physically embedded within the Hydro service area. Hence, metered energy entering the NP service area does not necessarily represent its true energy requirements from Hydro. EES Consulting understands that traditionally, NP energy was netted from load data such that NP would be allocated fewer costs. However, with the introduction of a demand charge, Hydro has deemed it necessary to adjust billing demand to account for the fact that at least some of the energy consumed at the time of peak demand would be supplied from NP generation sources.

A third feature of the proposed rate, which is indirectly related to peak demand, is a two-tiered energy or tail block rate structure. For monthly consumption below 420 GWh, NP would be charged an energy rate that is based on embedded energy-related and customer-related costs, including the rural deficit (see Hydro response to NP-143). Above 420 GWh, NP would be charged an energy rate that represents the incremental fuel cost of the Holyrood generating station, which we understand is used as a peaking unit. This energy block structure is intended to signal to NP the incremental cost of thermal production in times of high demand.

Because the basis for the proposed Hydro 2004 rate for NP is based on the SWMCI study, EES Consulting believes it relevant to comment upon this study. Overall, EES Consulting strongly agrees with statements and recommendations within the SWMCI report regarding the need for a demand price signal. We note that the SWMCI does not attempt to demonstrate that a primary cost driver of Hydro's system cost is peak demand, primarily because this issue was largely resolved in P.U. 7. On page 107 of that decision, the Board determined that on the balance of evidence presented, it is reasonable to assume that Hydro's system planning "is done on the basis of the peak occurring sometime in the winter period starting in December. It is also important to note a second conclusion of the Board on page 107 of P.U. 7 that the Hydro forecast peak "is derived from econometric modeling and is based on a combination of weather conditions and customer loads". This conclusion will be reflected within EES Consulting's comments on weather normalization.

EES Consulting has organized its comments into three sections: The Tail Block Rate, Weather Normalization, and Credits for NP Generation.

## 8.2 Tail Block Rate

As a general concept, EES Consulting recognizes the intent of the tail block energy rate. Set at the incremental fuel cost of higher cost energy from thermal units used during peak periods, the intent is to signal to the customer the incremental cost of bringing additional energy on line during a system peak. However, there are difficulties with developing such a rate under these circumstances.

The principle difficulty with this aspect of the proposal arises because one cannot colour-code electrons and determine who is 'causing' the more expensive generation to come on line. Under generally accepted cost of service principles, everyone consuming at the time of system peak shares responsibility for the higher cost generation. While it would be possible under the cost of service study to allocate everyone an appropriate pro-rata share of high and low cost generation, this does add an extra layer of complexity. Even after costs are fairly allocated to the appropriate parties, it is questionable whether or not the tail block price can affect the behaviour it seeks to remedy. Ideally, customers who consider this extra cost to outweigh the benefit of consuming in high demand periods would respond to the price signal by either reducing consumption in peak periods or by shifting consumption to low demand periods. However, a blocked energy rate will only reward efforts to cut back consumption because the energy blocking makes no distinction as to when the energy is consumed. An effort to shift consumption, even though it equally contributes to lower system costs at times of peak demand, is not rewarded under this proposed rate structure.

In the context of NP's circumstances a relevant example may be the case where a significant industrial load is added within the NP service area. In this case, NP will be at a distinct disadvantage in attracting new industrial load. Further, the Hydro tail block rate structure will provide little incentive for NP and the new industrial customer to work together to find ways to manage the new load around existing peak periods. Regardless of when the industrial load is used, this energy will count against the 420 GWh block.

With the addition of the demand charge, the tail block rate could also have the unintended consequence of negating the impact of the demand charge. The demand charge should promote an improved load factor by NP and its customers. At the same time, the higher tail block rate will send a signal to reduce consumption, which may not occur at peak periods. This would result in the potential for a higher load factor. To demonstrate the potential frequency that this conflicting price signal may arise, Table 10 below shows the number of billing periods that this proposed tail block would be a factor in the NP invoice. In all, NP would face the tail block rate in the 5-month winter season.

**Table 10**
**Likelihood That Tail Block Will be Used (Source: CA-132 NLH)**

| Month | NP GWh | Over 420 GWh Energy Block |
|---|---|---|
| January | 539.1 | Yes |
| February | 529.6 | Yes |
| March | 502.7 | Yes |
| April | 410.1 | |
| May | 360.1 | |
| June | 286.1 | |
| July | 272.5 | |
| August | 270.0 | |
| September | 274.4 | |
| October | 348.2 | |
| November | 423.3 | Yes |
| December | 525.3 | Yes |
| Total | 4,741.4 | |

In EES Consulting's opinion, the most obvious remedy to this particular problem is to design energy charges based on time-of-use. However, we do not see this option as having broad support at this time, nor is it operationally realistic to implement for the 2004 tariff. Ultimately, until there is a method to transparently cost and price generation resources based on how and when they are used, EES Consulting is of the opinion that the effectiveness of this particular price signal is not as great as portrayed by Hydro.

However, EES Consulting does consider that the demand charge component of the NP rate will provide a more appropriate price signal in a more transparent and less controversial manner. Because NP is the predominant load on the Island Interconnected System (Schedule 1.3.2 of Exhibit RDG-1 shows that over 70 percent of all Island Interconnected energy sales are attributable to NP), NP's peak demand is likely to be closely correlated with periods when higher cost peaking generators are being utilized. Provided that the demand rate is based on demand related costs from the cost study, the price signal of incrementally higher cost generation resources will be emphasized in the demand charge. This is because proportionally more of the cost of generating units for peak load are allocated on the basis of peak demand relative to base load generating costs.

EES Consulting is led to believe that Hydro also recognizes the value of the demand price signal in this regard. In its response to NP-178, Hydro states its belief that "the demand energy rate structure provides an efficient pricing signal since it services the dual purpose of collecting embedded demand costs while also providing a marginal pricing signal and thus is in the long-term best interest of system expansion planning."

## 8.3 Weather Normalization

EES Consulting does not regard Hydro's proposal to incorporate weather normalized billing demand as part of the NP rate as following generally accepted cost-causation principles or standard practice. By the very nature of weather normalization, one is adjusting consumption for what 'should have been'; this will involve some degree of professional judgement. In addition, weather normalizing demand will offset part of the intended benefits of having a demand charge.

In developing its recommendation for a demand based rate structure, SWMCI states on page 3 of its evidence that a key consideration is to ensure all parties remain revenue neutral and avoid earnings or revenue volatility. Included as a subset of this issue is the objective that the demand based rate should avoid "a windfall or penalty to either utility due to abnormal weather". This objective is used to justify the weather normalized billing demand that Hydro has adopted as part of its application as outlined by Hydro's response to PUB-150.

As discussed earlier, the Board has already determined on page 107 of P.U. 7 that peak winter demand plays a material role in system planning and development. EES Consulting agrees with the Board's assessment, and for this reason, we agree that the rate design should protect Hydro to some degree against under collecting rate revenues due to abnormally mild weather. Regardless of how mild a winter season turns out to be, Hydro is still expected to plan, size, and built the generation and delivery system to handle the reasonably predictable winter peak scenario. Customers directly benefit from this foresight during an abnormally cold winter, and therefore it is our opinion that a stable demand charge throughout the year is appropriate under these circumstances.

However, it is for the same reason that EES Consulting does not agree that surplus rate revenues due to abnormally cold weather should necessarily be characterized as a "windfall". To the extent Hydro must consider abnormally cold weather in its system development plan, we believe it to be inappropriate that customers are fully insulated from the rate impacts. Regardless of the impact on revenue forecast variances, the Hydro system is expected to provide service during reasonably predictable weather events, including those that can be characterized as "abnormal". In addition, each customer's reaction to these winter peak periods has a direct impact on the current and future design of the system. In this sense, we believe it entirely appropriate that customers face the full economic price signal at these times of system peak. Weather normalization does not follow generally accepted cost-of-service practices in this regard because it otherwise distorts a customer's actual contribution towards demand related costs deemed to vary with coincident peak.

If at the end of the tariff year, it is determined that Hydro's revenue forecast variance is materially and consistently positive and attributable to abnormally cold weather, then we would attribute the cause to one of two possibilities. First, it is possible that a utility may conservatively forecast its load. This can be a problem, either real or perceived, when regulating any utility on a prospective cost of service basis. All else equal, the utility has the incentive to conservatively forecast load such that revenues in excess of actual realized costs flow through to the shareholder. Addressing this perception becomes a delicate balance because clawing-back forecast variances might leave the utility with no incentive to innovate methods to provide better service at a lower cost.

The second possibility is that while the Hydro load forecast may be reasonable, the weather is still colder than forecast. In this case, there are a number of factors that would limit the financial windfall from demand revenues. First of all, Hydro can only supply a finite amount of energy past the designed capacity of the system for a finite length of time. Second, an effective rate design needs not to carry forward the full impact of unexpected peak into future billing periods. Priced at the $7.00 per kW-month proposed by Hydro, even if the actual peak were 100 MW (approximately 10 percent over NP Native Load as reported by Hydro in its response to PUB-182) over forecast this would have a $700,000 or 0.3 percent impact on total annual NP rate revenues (based on $258 million reported in Schedule 1.2 of Exhibit RDG-1). We note that in its response to NP-156, Hydro reports that its forecast variance on annual NP peak demand has averaged 5.9 percent and not exceeded 10.3 percent since 1993. Finally, if the surplus did become material, customers including NP have recourse to seek relief from the tariff on the grounds that the Board could not have foreseen the extreme weather when it originally approved the tariff as just and reasonable. If the surplus was instead smaller, but more frequently occurring, then one would have to question if the weather is indeed 'abnormal' and should instead be factored into a revised load forecast for the next tariff year.

It is for these reasons that EES Consulting does not consider weather normalized billing demand to be an appropriate feature of a demand based rate for NP. Over the long term, EES Consulting's preferred framework would be a ratcheted billing determinant, such as the following:

- The current month's metered coincident peak demand of all NP supply points.
- 90 percent (or some similar percentage, pending discussion and analysis) of the previous highest monthly billing demand from the past year.
- 85 percent (or some similar percentage, pending discussion and analysis) of the previous highest monthly billing demand from the past two years.

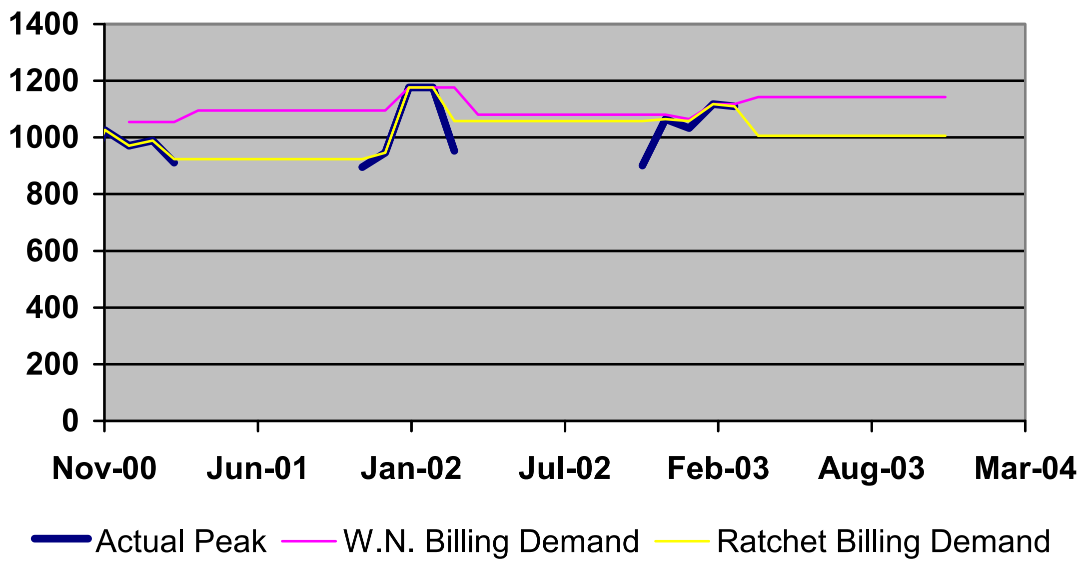
Based on Hydro's response to PUB-179, EES Consulting understands not all supply points are sufficiently metered, and some coordination between Hydro and NP may be necessary to agree upon an estimation formula. However, in its response to PUB-179, Hydro suggests a similar task would also be necessary to implement the rate structure it has proposed. For clarity, EES Consulting intends that the above ratchet formula framework be applied to NP's system peak and not the sum of each delivery point.

It is our opinion that the above 'ratchet' formula is a more conventional method to calculate billing demand in a manner that more closely follows cost of service principles. First of all, by using the customer's actual peak demand, the calculation recognizes that weather does have a real impact on how the system is designed and built. By including two years of history into the calculation, the ratchet also recognizes the fact that Hydro must design and build the system to meet the customer's peak demand, regardless of how infrequently it occurs. However, by using some declining percentage of actual peaks occurring in the past two years, this method addresses two important issues. First, price signals to current conditions receive greater emphasis; second, abnormal spikes in demand that could not have been reasonably forecast are not carried forward in full. NP's load is stable enough that any additional ratchets would rarely ever come into play, thus not justifying the extra administrative costs of carrying forward additional data.

The ratchet formula framework also satisfies Hydro's objective of minimizing revenue volatility, particularly in shoulder seasons where peak demand is often less predictable; under the ratchet formula framework, billing demand is generally assured to be no less than 90 percent of the previous winter's peak. This is not to say, however, that the demand ratchet allows Hydro a windfall in months where the ratchet is used. In designing a demand-based rate, Hydro must still meet the Board-approved revenue target, and would therefore still need to forecast billing demand, including use of the ratchet as part of this process. While this would result in a different demand rate from the proposed $7.00 per kW-month, the total amount paid by NP for the forecast test year would remain the same.

Figure 1 below compares weather normalized and ratchet billing determinants against actual metered demand. In its response to PUB-181, Hydro did not provide actual metered peak demand in off peak seasons, so the figure below assumes that the ratchet always applies in off-peak months. In order to make an apples-to-apples comparison, EES Consulting has grossed-up Hydro's proposed weather normalized billing demand by the 124.8 MW generation credit.

**Figure 1: Comparison of Billing Demands**




With the adoption of a ratcheted peak demand, EES Consulting also considers that it may be necessary to add a "Peak Demand Waiver" clause to the NP tariff. However, this will likely only be necessary if NP's actual system peak cannot be measured and must calculated. Surmising from the information and evidence collected by EES Consulting to date, this may indeed be an issue. A Peak Demand Waiver would help to further reduce the chances of setting artificial and unintended peaks due to planned system maintenance. For example, it is possible that with multiple delivery points, the metered energy at an individual delivery points is artificially inflated when power is re-routed to maintain service during maintenance.

By providing an outlet for the two utilities to agree in advance that a peak demand measurement that is not representative of an actual increase in consumption, the primary purpose of the Waiver is to ensure that the ratchet formula framework is reasonably and fairly applied to actual energy consumed. In addition, the Waiver may lead to cooperation and communication between the parties so that they may jointly plan system maintenance during non-peak hours and in off peak seasons.

A Peak Demand Waiver is likely to be more critical in circumstances where NP is billed individually at each supply point or where coincident peak is estimated based on the sum of non-coincident peak demands of each supply point. In either of these cases, re-routing power through a reduced number of supply points will have a noticeable impact on a calculated billing demand.

## 8.4 Credits for NP Generation

As discussed above, NP's generation resources become an issue when charging a demand rate to NP because at least some of those units are physically embedded within the Hydro service area. While NP continues to collect its own generation costs from its customers, this physical supply of energy is arriving through the Hydro system and passing through Hydro meters. If not properly adjusted, meter data could potentially distort Hydro's cost allocations by over-emphasizing the amount of Hydro energy actually delivered to NP. As a further complication, Hydro generally does not have dispatch control of the NP units within its system. While it is possible for Hydro to request the dispatch of NP units in times of need, Hydro's response to IC-300 would indicate that this has only happened on one occasion since 2000.

To adjust for this situation, Hydro has subtracted from NP's gross metered load the capacity and volume of energy provided by NP generating facilities outside of the NP service area. In the past, this represents a total 124.8 MW of NP generation capacity as well as the anticipated annual volume of NP generation from the forecast Hydro load. Within the cost of service study, this adjustment to load data reduces the amount of costs that are allocated to NP, which provides NP with an indirect financial credit for the generation capacity it adds to the Hydro Island Interconnected system.

Should this methodology continue to be used after the introduction of a demand based rate, Hydro has correctly identified the need for a further adjustment to the NP billing demand. This adjustment must account for the fact that at least some of the power consumed at the time of peak demand is supplied from NP generation sources within the Hydro service area. Hydro's proposal is based on recommendations of the SWMCI report, which suggest that the total 124.8 MW of capacity, rather than actual production at the time of the peak, should be subtracted from billing demand. Crediting NP for its full capacity, regardless of when or how the capacity is actually used, is the preferred option in the SWMCI report because:

- A demand based rate will encourage NP to use its generation resources at peak hours in order to "shave peak demand".
- The incentive to defer NP hydro production until the system peak may encourage NP to inefficiently spill water.
- The incentive to use NP thermal production at the system peak is socially inefficient because as the SWMCI evidence shows, NP's marginal costs of production are greater than Hydro's marginal costs of production at its Holyrood generating facility.

Thus, as SWMCI reasons, Hydro should give NP full credit as if it actually did shave peak demand, thus eliminating the incentive to actually do so, which will free NP to use its resources at another time.

EES Consulting makes two observations regarding the application of the generation credit. They are as follows:

- ***The generation credit inappropriately reduces the amount NP pays for transmission costs***

Because NP generating units are located within the Hydro service area, NP still requires Hydro transmission capacity to deliver the energy to its load centres. However, EES Consulting notes that both the Hydro cost study and the resulting rate design do not sufficiently unbundle transmission from generation to ensure that NP pays the full price of Hydro transmission services. The resulting rate means that NP will pay proportionally less for transmission than an otherwise equivalent customer who does not posses generation facilities within the Hydro service area.

On the rate side, Hydro's bundled rate recovers both transmission and generation costs using a single set of demand and energy charges. Thus, by crediting NP's billing demand against the full demand charge, the calculation is also indirectly crediting NP for transmission capacity at the same time.

While the generation credit is necessary to ensure that Hydro does not over-collect generation costs, the manner in which it is used in the cost study under-allocates NP its appropriate share of transmission costs. On the cost side, Hydro relies upon a single allocator for apportioning generation and transmission costs to NP. This allocator is built on load data after a credit for NP generation is applied. Thus when this single allocator is used to apportion transmission costs, NP does not receive its full share of transmission costs.

EES Consulting has provided an example, based on figures from Hydro's application, in the tables below to illustrate this point.

**Table 11**
**Gross and Net Allocators**

| | Peak Demand (Gross MW) | CP Allocator (Gross) | Peak Demand (Net MW) | CP Allocator (Net) |
|---|---|---|---|---|
| NP | 1,084 | 1,084/1,251 =87% | 1,037 | 1,037/1,204 =86% |
| All Others | 167 | 167/1,251 =13% | 167 | 167/1,204 =14% |
| Total | 1,251 | 100% | 1,204 | 100% |

Table 11 above provides a sample calculation of two sets of coincident peak allocation factors, one gross and one net of the NP generation credit of 124.8 MW. Using gross load data, the above table shows that NP contributes 1,084 MW to a total coincident peak demand of 1,251 MW; using gross data to calculate allocators would result in NP being allocated 87 percent of all demand related costs deemed to be allocated on coincident peak demand. However, because NP provides some of this generation capacity, it is not appropriate to allocate generation costs as if its load were 1,084 MW. Once load data is adjusted to credit NP for 124.8 MW of its own generation, NP is now allocated 86 percent of coincident peak demand related costs.

These allocation factors are carried forward into Table 12 below, where an illustrative cost allocation exercise is performed on both generation and transmission costs.

**Table 12**
**Illustrative Cost Allocation, Hydro Method ($,000)**

| Function | Demand Related Cost | Allocated to NP | Allocated to All Others |
|---|---|---|---|
| Generation | 80,920 | *86%=69,672 | *14%=11,248 |
| Transmission | 29,447 | *86%=25,354 | *14%=4,093 |
| Total | 110,367 | 95,026 | 15,341 |

In the above table, the cost of service study has already identified some $110 million of demand related costs to be allocated based on coincident peak demand. This study also determined that of this amount, $81 million is functionalized as generation and $29 million is functionalized as transmission. However, in the Hydro cost study, the net allocation factor of 87 percent is used to allocate all demand related costs to the respective rate classes.

The problem with the above method is that from a transmission perspective, NP is still relying upon the full 1,084 MW of capacity despite being allocated costs on the basis of 1,037 MW. Table 13 below demonstrates how this allocation should be performed. In this example, using only the credit-adjusted allocator for both generation and transmission means that $147,000 is inappropriately allocated to other customers instead of NP.

**Table 13**
**Illustrative Cost Allocation, Full Transmission Costing Method ($,000)**

| Function | Demand Related Cost | Allocated to NP | Allocated to All Others |
|---|---|---|---|
| Generation | 80,920 | *86%=69,672 | *14%=11,248 |
| Transmission | 29,447 | *87%=25,501 | *13%=3,946 |
| Total | 110,367 | 95,173 | 15,194 |

- ***Crediting total capacity, not actual output, inappropriately dulls long term incentives***

EES Consulting does not agree that the incentive for NP to use its own generating units in times of peak demand is necessarily a wrong or undesirable outcome. Much of the justification to take away this pricing incentive is hinged upon SWMCI's comparison of NP's thermal and Hydro's Holyrood marginal production costs. Even if EES Consulting were to accept this conclusion on face value, we do not believe it appropriate that the

Board-approved methodology should close the door on a possibility without providing a price that will provide an incentive to innovate new solutions.

Over the long run, NP is in a better position to understand its customers and load requirements and therefore with the correct incentives may also be in a better position to determine whose generation should be used at times of peak demand. With the proper incentives, it may be that NP can find ways to reduce its fuel costs or improve operational efficiency at its thermal units in periods of peak demand. Furthermore, if Hydro were to have an embedded cost advantage in base load hours due to economies of scale, it may be appropriate for NP to defer the use of its hydro resources until peak periods. Provided that such resources are priced appropriately, EES Consulting does not consider it likely that NP would have the financial incentive to spill water, as this surplus energy would always have some positive value to the overall system.

It is also important to note that if NP chooses to use its generating facilities at times of peak demand, this does not mean that Hydro is at risk for not recovering its Board-approved costs. In the short term, a ratchet formula framework for billing demand would appropriately protect Hydro from demand related stranded costs. Over time, the ratchet would slowly decline, but this will also allow Hydro time to revise and seek regulatory approval of a new load forecast that incorporates NP's new behaviour.

Over the long run, NP may even consider building additional or upgrading existing peaking capacity to shave peak demand. However, this is a risk that Hydro faces regardless of how NP is credited for its capacity. Under such circumstances, we understand that NP would still need to obtain regulatory approval of any capital additions or upgrades. If at that time the Board determined Hydro stranded costs were material, it would still have the option to disapprove of the NP proposal or to order that Hydro may recover its stranded costs from NP or some other party. However, because of the long lead time necessary to bring material amounts of new capacity on line, it may be that Hydro's generating capacity may not be displaced at all due to load growth on the remaining Island Interconnected system.

As a long run alternative, we believe it would be more appropriate to develop a framework of price signals that will allow NP to make an informed decision whether or not it should dispatch its own generation resources at times of system peak. However, because the current methodology does not provide for a price signal that reflects actual cost impacts, a solution is not as simple as crediting NP billing demand by its actual metered production during the monthly peak.

As discussed above, when the generation credit is applied to the billing demand of a bundled rate, NP is also credited transmission costs. For this reason, EES Consulting believes it more likely that NP will inefficiently favour its own generating facilities during periods of peak demand. By using its own generating resources, NP would effectively receive incremental transmission capacity for no extra charge.

### ■ *Options*

EES Consulting can suggest two methods to address this issue. The first, and perhaps the least disruptive in the short term, is to develop a second set of allocators that are not based on the NP generation credit and to unbundle the NP rate into generation and transmission components. However, this option does not address the incentive for inefficient dispatch that was raised by Hydro. Without instituting a centralized dispatch system, we believe that this particular incentive problem will always exist. As a second-best solution, EES Consulting recommends that the Board considers initiating the development of a NP Generation Tariff to be charged to Hydro.

The most immediate option to address the difficulties discussed above is to unbundle cost allocations and NP rate design into generation and transmission components. This allows credit for NP generation to be applied for allocating generating costs only. Similarly, credits for NP generation can be applied to the billing demand for generation charges. The NP demand rate would be calculated as follows:

- Generation demand charge of $X / kW applied to a billing demand *net* of the generation credit
- Transmission demand charge of $Y / kW applied to a billing demand *gross* of the generation credit
- The total demand revenues would continue to equal the Board-approved demand-related costs allocated to NP.

However, EES Consulting is still hesitant to recommend an option that continues to credit NP generation from the Hydro load forecast. This method is not fully transparent in the sense that NP generation forecasts have material influence on Hydro allocation factors and therefore, Hydro rates. Unless the regulatory process is precisely scheduled, there will often be situations where the NP generation forecast used in the Hydro proceeding is either not yet Board-approved or Board-approved, but obsolete. This would inevitably put Hydro in the understandably difficult situation to defend a generation forecast for generating units it neither owns nor dispatches.

The inefficient dispatch issue raised by Hydro remains a problem under this option. When faced with choosing the source for the next incremental unit of supply, NP will be comparing its own incremental fuel costs against the incremental change in Hydro's fully embedded rate. This is because there is no financial transaction between the two utilities for NP's generation to match the operational flow of energy. Thus, NP may only compare the Hydro to its own internal generation costs. In all likelihood NP's incremental fuel costs will be less than Hydro's fully embedded rate. Consequently, NP will tend to favour its own sources even if it is not optimal from an overall system cost perspective.

In EES Consulting's opinion, this incentive problem will remain an issue until all generation on the Island Interconnected System is centrally dispatched according to a

Board-approved stacking order. This is because it is difficult, if not impossible, to devise a price-signal system that encourages multiple generators to self-dispatch based on increasing order of marginal cost.

As a second-best solution, EES Consulting advocates the development of a NP Generation Tariff payable by Hydro. If the financial impacts to NP of running its generators in the Hydro service area are also governed by a tariff with demand and energy components, this will at least NP makes an apples-to-apples comparison when choosing the source of the next incremental unit of supply. This would eliminate the need for the NP generation credit because Hydro would now have the financial rights to all metered power at the point of deliver.

The Generation Tariff option is purely a paper transaction; NP and Hydro operations do not necessarily change. However, instead of NP recovering the costs of NP generation directly from its customers, NP would initially recover the costs from Hydro. To ensure that customers are held whole by this transaction, the NP Generation Tariff structure should precisely follow the same demand-related, energy-related, and customer-related proportions as are currently approved in the NP cost of service study. Hydro would treat this cost as a flow-through as it would with supply from any other third-party supplier, except that as part of the cost of service study, the NP Generation Tariff would be directly assigned to NP. As a result, NP customers will still pay for NP generation in the end.

Although the Generation Tariff option does require the development of a new financial transaction between NP and Hydro, there are four benefits associated with its implementation.

- Without the requirement to credit Hydro's load forecast for NP generation, the NP generation forecast does not become an issue for the Hydro rate application. In its place, Hydro will need to forecast the financial impacts of NP generation, but as long as this cost is considered a flow-through to be directly assigned to NP customers, an accurate forecast need not be as critical.
- This method is robust in allocating to and collecting from NP the transmission costs and transmission losses associated with NP's production. NP provides and sells its power at the plant gate and by the time NP purchases the power back, Hydro has added transmission costs and losses according to the same methodology it uses for every other customer. Provided that the NP Generation Tariff is treated as a directly assigned flow through cost, the power itself will be re-purchased at the same price.
- Once there is an initial financial transaction for the sale of NP's generation, then when NP must decide between its own sources and Hydro sources, the decision is on an apples-to-apples basis. NP now compares the change in revenues from its own tariff against the change in costs of paying Hydro's rate. On a net basis, NP would be "shaving" the financial consequences of a new Hydro generation peak instead of peak shaving in an operational sense.

- When generators such as NP are paid compensation from the transmission system, it becomes easier to transition to a system of centralized dispatch. With a Board-approved stacking order, centralized dispatch can prioritize units according to incremental cost. Once units are dispatched, NP will be compensated with a similar Generation Tariff so that it is fully compensated for Board-approved embedded costs.

## 8.5 EES Consulting Recommendation

EES Consulting believes that the process of developing a framework of appropriate price signals should begin with the 2004 test year. Based on our review of Board Decision P.U. 7, it would appear to us that no party disputes, at least on a theoretical level, that a demand based rate structure is appropriate for NP. In response to RFIs, Hydro has expressed its optimism that this issue can be resolved at the technical conference portion of the hearing. To that end, we would recommend that the Board consider approving the Hydro rate proposal subject to two modifications.

The first recommendation is that the NP rate should incorporate a demand ratchet formula framework instead of weather normalization. As explained above, the demand ratchet formula framework more appropriately reflects cost of service principles than would weather normalization. In our opinion, the demand ratchet formula framework also adequately addresses concerns of the involved parties regarding volatility. It is important to note that the use of a demand ratchet formula framework will impact Hydro's forecast billing demand determinants and the calculated unit cost resulting in the proposed $7.00 per kW-month demand charge. Furthermore, the implementation of a demand ratchet formula framework may require Hydro and NP to discuss the implementation of a Peak Demand Waiver.

The second recommendation is that, at a minimum, the NP generation credit should not be applicable to allocators used to apportion transmission costs; nor should the NP generation credit be applied to the billing demand associated with the transmission portion of the rate. As a means to address this issue, the NP Generation Tariff option is preferred. Implementation of this option ensures that financial transactions better correspond with the operational flow of energy, thus making it more transparent and robust to changes in cost and load. Moreover, this option sets a framework for a centralized generation dispatch system should it become necessary in the future.

If the second recommendation is not adopted, then it is our position that the Board should consider directing Hydro to unbundle its cost study such that generation costs are allocated using load data net of the generation credit and transmission costs are allocated using load data gross of the generation credit. The proposed demand rate would then be unbundled into generation and transmission charges in order that the generation credit only applies to generation charges

# EXHIBIT A

# CV OF GAIL TABONE

Exhibit A

# PROFESSIONAL EXPERIENCE AND BACKGROUND OF

# GAIL D. TABONE

## EDUCATION

M.S., Agricultural and Applied Economics
University of Minnesota
St. Paul, MN (1984)

B.S., Economics
University of Minnesota
Minneapolis, MN (1982)

## EMPLOYMENT

| | |
|---|---|
| August 1988 to Present | EES Consulting<br>570 Kirkland Way, Suite 200<br>Kirkland, Washington 98033<br>Management Consulting Firm |
| Position: | Vice President |
| Responsibilities: | Preparation of projects including cost of service studies, rate designs, load forecasting, load research, least cost planning and financial analyses. Provide expert testimony on least cost planning, forecasting and cost of service analysis. |
| Activities: | Design and implement computer based cost of service models. Prepare end-use and econometric load forecasts for electric utilities. Prepare statistical design for load research programs and analyze resulting load data. Conduct research and design models for least cost planning, including resource evaluation. |
| January 1986 to June 1988 | United Power Association<br>Elk River, MN<br>Generation and Transmission Cooperative |
| Position: | Power Requirements Analyst |
| Responsibilities: | Preparation of end-use forecast for 15 member cooperatives. |
| Activities: | Design end-use forecasting model and prepare forecasts of specific end-uses of electricity. Conduct load pattern analysis and weather normalization. Analyze data on load management programs. |

# EXHIBIT B

# CV OF NIGEL CHYMKO

# Curriculum Vitae

## Nigel Chymko

**EDUCATION**

Bachelor of Administration (Quantitative Analysis) - 1970
University of Regina
Regina, Saskatchewan

Banff School of Advanced Management - 1983
Banff, Alberta

Management for Accounting and Financial Executives - 1981
University of Western Ontario

**EMPLOYMENT**

| | |
|---|---|
| **May 1998 - Present** | **EES Consulting Ltd.** |
| Position: | Vice President |

Responsibilities:

- overall supervision and quality control for EES Consulting's electric, water, wastewater and natural gas engagements
- principal responsible for the firm's office in Calgary

Activities:

- supervise and provide project management expertise and technical support for energy aggregation programs, utility mergers and acquisitions, energy acquisition and risk management, strategic, business and financial planning and analysis, profitability, rates and cost of service, industry deregulation, restructuring and organizational needs, utility operations, market forecasting, research and analysis, regulatory services and educational training
- participation in regulatory applications and industry deregulation
- presentations to clients, their Boards and Regulators, on project analysis, utility economics, strategic planning, finance and utility operations
- contract negotiation and administration of request for proposals

**1980 – April 1998 ENMAX Corporation, formally City of Calgary's Electric System**

*1996 – April 1998*
Position: Assistant General Manager, Energy Trading & Business Affairs

Responsibilities:

- provided guidance and leadership to a business unit whose focus was to strategically position the utility in a restructured competitive marketplace. This was accomplished through four major areas: Energy Trading, Business Planning and Regulatory Affairs, Financial Services and Corporate Communication
- responsible for directing strategic, business and financial planning, controllership, regulatory affairs, wholesale portfolio management and corporate communication for the electric utility
- functioned as a member of the utility's executive and for the purpose of the City's corporate regulatory matters, functionally reported to the City's Chief Executive Officer
- directed the City's activities of a regulatory nature including electric, gas and telecommunications
- acted as a resource and responsible for the direction and administration of the business of the Gas, Power and Telecommunications Committee

Activities:

- positioned the City to take advantage of the next steps in electric deregulation
- lead the development of a three year business plan that City Council approved focusing the utility to compete in a new electric marketplace
- successfully avoided any rate increase from 1993 - 1998
- key contributor in the establishment of ENMAX Corporation as a wholly owned subsidiary corporation including identifying reporting requirements to the Board of Directors and development of a corporate name and logo
- lead the financial restructuring, profitability analysis and rate unbundling to meet incorporation requirements
- lead negotiations achieving settlements for provincial generation and transmission costs

*1995*
Position: Assistant General Manager, Customer Energy, Sales and Service

Responsibilities:

- this position was created during the first phase of restructuring of the Electric System
- responsible for directing a newly created business unit which included Marketing, Customer Sales and Services and Energy Procurement and Delivery

- responsibilities included directing market forecasting and research, competitor/technology intelligence, cost of service and profitability analysis, rate design and pricing, developing a single point of contact for the utility's customers, power pool operations, managing supply contracts and operational control of utility's facilities including emergency power restoration
- continued to be responsible for directing the corporate regulatory affairs activities

Activities:

- set up an energy trading and portfolio management function to ensure that the utility could manage its wholesale portfolio with the passing of the Alberta Electric Utilities Act
- ensured Calgary's interests were protected in the legislative development of the Alberta Electric Utilities Act
- initiated work on customer segmentation and profitability analysis to allow the utility to unbundle its pricing and undertook the development of the corporate name and logo
- instrumental and involved in the utility's major organizational restructuring and restaffing process

*1980 - 1994*
Position: Manager, Business Planning and Regulatory Affairs

Responsibilities:

- managed through three areas that included Financial Regulation, Rate Regulation and Controllership and Financial Support
- responsible for directing the utility's diverse financial activities including customer rates and cost of service, accounting and management control, financial policy and planning and the overall strategic management and business planning for the utility
- responsible for directing the corporation's activities of a regulatory nature including electric, gas and telecommunications

Activities:

- initiated strategic and business planning which has positioned the Electric System to take advantage of the transition to deregulation and the emerging competitive environment
- initiated and implemented comprehensive changes to the planning, budgeting, accounting and reporting systems of the City's largest department to provide senior management with accurate and timely information for improved decision making
- developed and implemented financial policies, sophisticated software for planning analysis, management reporting to meeting City Council directives and the changing regulatory environment. Segregated the business activities of the utility into cost components reflecting the different types of businesses it actually carries out to ensure appropriate cost recovery by type of business
- provided Alberta Energy with a regulatory framework option which is the basis for the new Alberta Electric Utilities Act

- participated in the legislative development of the Alberta Electric Energy Marketing Act (EEMA) to ensure fair annual compensation to the City for the use of its high voltage facilities. Negotiated annually with the Provincial Government
- provided improved reporting, coordination and administration of the business of Gas, Power and Telecommunications Committee of Calgary City Council

**1979** **PanCanadian Petroleum Limited**

Position: Supervisor, Economics and Planning

Responsibilities:

- responsible for developing oil and gas price forecasts, inflation factors, exchange rates and other economic indicators which were used as the basis for the company's financial plan and for economic evaluation of investments
- established the economic criteria to be used for corporate planning and project evaluations and provided support to operating divisions in the area of economic evaluations
- approved the economics for all major capital expenditures and reviewed associated cost benefit analysis

**1970 - 1978** **TransAlta Utilities Corporation**

Position: Supervisor, Economics and Forecasts (1975 – 1978)
Systems Analyst (1970 – 1974)

Responsibilities:

- evaluated customer quotation procedures and policies, established contract parameters and conducted evaluations on the purchase and sale of facilities
- developed the company's customer, load and revenue forecasts
- represented the company on long term energy requirements before Provincial agencies and planning committees
- coordinated and developed computerized accounting systems

**PROFESSIONAL ASSOCIATIONS**

Board Trustee, Northwest Public Power Association

Calgary Chamber of Commerce

Canadian Electricity Association

Canadian Energy Research Institute

# EXHIBIT C

# SUPPORTING DOCUMENTATION,

# PEAK CREDIT METHOD

**Table 1**
**Comparison of Classificaiton of Costs**

| System | Current Load Factor Method Demand Costs as % of Total Revenue Requirement | Proposed Peak Credit Method Demand Costs as % of Total Revenue Requirement |
|---|---|---|
| Island Interconnected | 18.5% | 21.9% |
| Island Isolated | 29.0% | 63.5% |
| Labrador Isolated | 16.9% | 43.6% |
| L'Anse au Loup | 27.7% | 27.7% |
| Labrador Interconnected | 48.2% | 21.2% |
| Total | 19.2% | 24.3% |

**Table 2**
**Impacts by Customer Class Due to change to Peak Credit Method**
**Total Revenue Requirement**

| | Residential | | Commercial | | Industrial | | Newfoundland Power | | Other | |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** |
| Island Interconnected | -$175,111 | -0.5% | $55,911 | 0.3% | $1,962,779 | 3.8% | -$1,839,656 | -0.8% | -$3,923 | -0.4% |
| Island Isolated | $254,478 | 4.3% | -$263,101 | -11.4% | $0 | 0.0% | $0 | 0.0% | $8,624 | 7.0% |
| Labrador Isolated | $763,661 | 6.4% | -$785,541 | -9.8% | $0 | 0.0% | $0 | 0.0% | $21,881 | 9.8% |
| L'Anse au Loup | $0 | 0.0% | $0 | 0.0% | $0 | 0.0% | $0 | 0.0% | $0 | 0.0% |
| Labrador Interconnected | -$146,493 | -2.1% | $53,848 | 1.5% | $93,681 | 3.4% | $0 | 0.0% | -$1,035 | -0.6% |
| Total | $696,534 | 1.1% | -$938,884 | -2.9% | $2,056,460 | 3.7% | -$1,839,656 | -0.8% | $25,547 | 1.7% |

**NEWFOUNDLAND & LABRADOR HYDRO**
**2004 Forecast Cost of Service**
**Functionalization & Classification Ratios**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Production | | Rural Prod & | Distribution | | | | | | | | | | | Specifically |
| Line | | Total | Production | & Transmission | Transmission | Transmission | Substations | Primary Lines | | Line Transformers | | Secondary Lines | | Services | Meters | Street Lighting | Accounting | Assigned |
| No. | Description | Amount | Demand | Energy | Demand | Demand | Demand | Demand | Customer | Demand | Customer | Demand | Customer | Customer | Customer | Customer | Customer | Customer |
| | | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) |
| | **Generation** | | | | | | | | | | | | | | | | | |
| 1 | Hydraulic | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 2 | Hydraulic - GNP | 100% | 0.00% | 0.00% | | 100.0% | | | | | | | | | | | | |
| 3 | Holyrood | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 4 | Gas Tur Island Intercnctd | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 5 | Diesel Island Intercnctd - GNP | 100% | 0.00% | 0.00% | | 100.0% | | | | | | | | | | | | |
| 6 | Dsl / Gas Tur Island Isolated | 100% | 100.00% | 0.00% | | | | | | | | | | | | | | |
| 7 | Dsl / Gas Tur Labrador Isolated | 100% | 100.00% | 0.00% | | | | | | | | | | | | | | |
| 8 | Dsl / Gas Tur L'Anse au Loup | 100% | 100.00% | 0.00% | | | | | | | | | | | | | | |
| 9 | Dsl / Gas Tur Labrador Intercnctd | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| | **Fuel** | | | | | | | | | | | | | | | | | |
| 10 | No. 6 Fuel | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 11 | Gas Tur Island Intercnctd | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 12 | Diesel Island Intercnctd - GNP | 100% | 0.00% | 0.00% | | 100.0% | | | | | | | | | | | | |
| 13 | Dsl / Gas Tur Island / Lab Isolated | 100% | 0.00% | 100.00% | | | | | | | | | | | | | | |
| 14 | Dsl / Gas Tur L'Anse au Loup | 100% | 0.00% | 100.00% | | | | | | | | | | | | | | |
| 15 | Dsl / Gas Tur Labrador Intercnctd | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| | **Transmission Lines & Terminals** | | | | | | | | | | | | | | | | | |
| 16 | Lines | 100% | | 0.00% | 100% | | | | | | | | | | | | | |
| 17 | Lines - Hydraulic | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 18 | Lines - Customer Specific | 100% | | | | | | | | | | | | | | | | 100% |
| 19 | Terminal Stations | 100% | | 0.00% | 100% | | | | | | | | | | | | | |
| 20 | Term Stns - Hydraulic | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 21 | Term Stns - Holyrood | 100% | 22.00% | 78.00% | | | | | | | | | | | | | | |
| 22 | Term Stns - Gas Tur | 100% | 100% | | | | | | | | | | | | | | | |
| 23 | Term Stns - Diesel GNP | 100% | 0.00% | 0.00% | | 100.0% | | | | | | | | | | | | |
| 24 | Terminal Stations - Distribution | 100% | | | | | 100% | | | | | | | | | | | |
| 25 | Term Stns - Custmr Specific | 100% | | | | | | | | | | | | | | | | 100% |
| 26 | Rural Lines | 100% | | | | 100.0% | | | | | | | | | | | | |
| 27 | Rural Terminal Stations | 100% | | | | 100.0% | | | | | | | | | | | | |

| | Combine Cycle | Simple Cycle | |
|---|---|---|---|
| Capacity (MW) | 420 | 100 | From PacifiCorp IRP |
| Hours Run | 8760 | 200 | |
| Capacity Factor | 95% | 95% | |
| Energy (MWh) | 3,495,240 | 19,000 | Calculated |
| Heat Rate (Btu/kWh) | 7235 | 12176 | From PacifiCorp IRP |
| Fuel (Therms) | 252,880,614 | 2,313,440 | Calculated |
| Fuel Price ($/Therm) | 0.332 | 0.332 | |
| Capital Cost ($/kW) | 770 | 498.5 | From PacifiCorp IRP |
| Fixed O&M ($/kW-yr) | 8.29 | 11.23 | From PacifiCorp IRP |
| Variable O&M ($/MWh) | 1.94 | 3.14 | From PacifiCorp IRP |
| Fuel Costs | $83,956,364 | $768,062 | Calculated |
| Debt Service Cost | $30,526,672 | $4,705,487 | Calculated |
| Fixed O&M | $3,481,800 | $1,123,000 | Calculated |
| Variable O&M | $6,780,766 | $59,660 | Calculated |
| Total Annual Cost | $124,745,602 | $6,656,209 | Calculated |
| Unit Cost | $297.01 | $66.56 | Calculated |
| | | | |
| Demand Share | | 22% | |

## SUPPLY SIDE RESOURCES

### Table C.18 Potential Supply Side Resources

| Supply Side Resources | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel | Installation Location | Technology | Plant Lead Time - Months. | Capacity MW | Maximum Capacity Addition per Site | Capital Cost in $/kW (Average) | Annual Heat Rate HHV | Maint. Outage Rate (1-EAF-EFOR) | Equivalent Forced Outage Rate (EFOR) | Fuel Cost $/mmBtu | Var. O&M $/MWh | Fixed O&M in $/kW-yr |
| **East Side Options (4500'):** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | |
| Extend Existing Carbon Units 10 years | Utah Coal | Utah | PC-Sub | 0 | 175 | 0 | $42 | 11,350 | 4.3% | 4.7% | $0.61 | $0.25 | $54.50 |
| Hunter 4 - PC | Utah Coal | Utah | PC-Sub | 48 | 575 | 575 | $1,389 | 9,483 | 5.0% | 4.0% | $0.72 | $0.73 | $27.39 |
| Utah Greenfield PC | Utah Coal | Utah | PC-Sub (2x500) | 60 | 575 | 1,150 | $1,431 | 9,483 | 5.0% | 4.0% | $1.00 | $0.73 | $33.94 |
| Utah Greenfield IGCC | Utah Coal | Utah | IGCC - 7FA (2x1) | 66 | 370 | 740 | $1,797 | 8,311 | 15.0% | 10.0% | $1.00 | $1.83 | $25.94 |
| Wyoming Greenfield PC | PRB | Wyoming | PC-Sub - PRB | 66 | 575 | 1,150 | $1,501 | 9,483 | 5.0% | 4.0% | $0.84 | $0.73 | $33.94 |
| | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | |
| Microturbines | Nat. Gas | Utah | Capstone | 12 | 0.020 | 0.204 | $2,312 | 14,321 | 1.0% | 1.0% | Nat. Gas | $7.93 | $433.25 |
| Fuel Cells | Nat. Gas | Utah | SOFC (Westinghouse) | 12 | 0.225 | 2 | $1,500 | 5,688 | 1.0% | 1.0% | Nat. Gas | $2.13 | $53.78 |
| Extend Existing Gadsby Units 10 years | Nat. Gas | Utah | Steam Boilers | 0 | 235 | 235 | $9 | 12,950 | 1.0% | 3.7% | Nat. Gas | $0.10 | $27.61 |
| Utah CHP (Cogen. - CT) | Nat. Gas | Utah | 7FA (1x1) - 100K Steam | 41 | 190 | 190 | $1,025 | 7,136 | 4.1% | 4.6% | Nat. Gas | $1.94 | $13.31 |
| Utah CHP (Non CT) | Nat. Gas | Utah | Topping Turbine | 24 | 25 | 50 | $659 | 5,305 | 5.0% | 10.0% | Nat. Gas | $0.15 | $25.69 |
| Greenfield SCCT Aero | Nat. Gas | Utah | SCCT - 2 - LM6000 | 12 | 80 | 400 | $844 | 10,233 | 0.0% | 10.2% | Nat. Gas | $3.90 | $11.45 |
| Greenfield SCCT Frame | Nat. Gas | Utah | SCCT - 1 - 501D5 | 24 | 100 | 400 | $539 | 12,176 | 0.0% | 10.2% | Nat. Gas | $3.14 | $11.23 |
| Brownfield SCCT Frame (Mona) | Nat. Gas | Utah | SCCT - 1 - 501D5 | 24 | 100 | 400 | $458 | 12,176 | 0.0% | 10.2% | Nat. Gas | $3.14 | $11.23 |
| Gadsby Repowering (1x1) | Nat. Gas | Utah | CCCT - 7FA (1x1) | 41 | 210 | 210 | $927 | 7,235 | 4.1% | 4.6% | Nat. Gas | $1.94 | $13.31 |
| Gadsby Repowering Duct Firing (1x1) | Nat. Gas | Utah | 2-7FA Duct Firing | 41 | 30 | 30 | $253 | 11,998 | 4.1% | 4.6% | Nat. Gas | $0.00 | $3.80 |
| Gadsby Repowering (2x1) | Nat. Gas | Utah | CCCT - 7FA (2x1) | 41 | 440 | 440 | $670 | 7,074 | 4.1% | 4.6% | Nat. Gas | $1.77 | $7.83 |
| Gadsby Repowering Duct Firing (2x1) | Nat. Gas | Utah | 2-7FA Duct Firing | 41 | 70 | 70 | $205 | 9,219 | 4.1% | 4.6% | Nat. Gas | $0.00 | $3.80 |
| Greenfield CCCT 2 - 1x1 (Intermediate Load) | Nat. Gas | Utah | CCCT - 7FA (1x1) | 48 | 420 | 840 | $770 | 7,235 | 4.1% | 4.6% | Nat. Gas | $1.94 | $8.29 |
| Greenfield CCCT Duct Firing 2 - 1x1 | Nat. Gas | Utah | 2-7FA Duct Firing | 48 | 60 | 120 | $253 | 11,998 | 4.1% | 4.6% | Nat. Gas | $0.00 | $3.80 |
| Greenfield CCCT 2x1 | Nat. Gas | Utah | CCCT - 7FA (2x1) | 48 | 440 | 880 | $706 | 7,074 | 4.1% | 4.6% | Nat. Gas | $1.77 | $7.83 |
| Greenfield CCCT Duct Firing 2x1 | Nat. Gas | Utah | 7FA Duct Firing | 48 | 70 | 140 | $205 | 9,219 | 4.1% | 4.6% | Nat. Gas | $0.00 | $3.08 |
| Greenfield CCCT "G" 2x1 | Nat. Gas | Utah | CCCT - 501G (2x1) | 48 | 615 | 1,230 | $650 | 6,945 | 4.1% | 4.6% | Nat. Gas | $1.65 | $6.09 |
| Greenfield CCCT "G" Duct Firing 2x1 | Nat. Gas | Utah | 501G Duct Firing | 48 | 110 | 220 | $229 | 8,554 | 4.1% | 4.6% | Nat. Gas | $0.00 | $3.43 |
| | | | | | | | | | | | | | |
| **Other - Renewables** | | | | | | | | | | | | | |
| Wind - Wyoming (36% CF) | n/a | Wyoming | 1650 kW machines | 12 | 50 | 200 | $1,000 | n/a | n/a | n/a | n/a | $0.00 | $22.65 |
| Wind - Utah | n/a | Utah | 1650 kW machines | 12 | 50 | 200 | $1,000 | n/a | n/a | n/a | n/a | $0.00 | $22.65 |
| Blundell Upgrade | Geothermal | Utah | K-ST | 24 | 50 | 50 | $1,880 | 10,000 | 4.1% | 0.9% | $18/MWh | $0.10 | $16.00 |
| Pumped Storage | Water/coal | Nevada | Pumped Hydro | 36 | 200 | 400 | $850 | 13,924 | n/a | n/a | $1.00 | $0.51 | $10.00 |
| Solar | Solar | Utah | Thermal (Solar II) | 48 | 200 | 200 | $5,028 | n/a | n/a | n/a | n/a | $0.20 | $41.18 |

| Technology Code: | | |
|---|---|---|
| | PC-Sub | Pulverized Coal - Subcritical |
| | IGCC | Intergrated Gasification Combined Cycle (Clean Coal Tech.) |
| | SCCT | Simple Cycle Combustion Turbine |
| | CCCT | Combined Cycle Combustion Turbine |
| | CCCT | Repower Combined Cycle |
| | K-ST | Kalina based Steam Turbine |
| | Cogen | Cogeneration |

Elevation Correction Factor for east to west

# EXHIBIT D

# SUPPORTING DOCUMENTATION,

# MINIMUM SYSTEM METHOD

**Table 3**
**Comparison of Zero-Intercept and Minimum System**

| | Zero Intercept | | Minimum System | |
|---|---|---|---|---|
| **Distribution Account** | **Customer %** | **Demand %** | **Customer %** | **Demand %** |
| Substation Structures & Equipment | | 100.0% | | 100.0% |
| Land & Land Improvements - by Sub-function: | | | | |
| Primary | 11.3% | 88.7% | 15.7% | 84.3% |
| Secondary | 41.7% | 58.3% | 15.7% | 84.3% |
| Land & Land Improvements | 15.9% | 84.1% | 15.7% | 84.3% |
| Poles - by Subfunction: | | | | |
| 3 phase - Primary | | 100.0% | 41.1% | 58.9% |
| Other Primary | 54.3% | 45.7% | 41.1% | 58.9% |
| Secondary | 54.3% | 45.7% | 41.1% | 58.9% |
| Poles | 32.0% | 68.0% | 41.1% | 58.9% |
| Primary Condctr & Equip | 11.3% | 88.7% | 15.7% | 84.3% |
| Submarine Conductor | | 100.0% | | 100.0% |
| Transformers | 63.9% | 36.1% | 27.0% | 73.0% |
| Secondary Condctr & Equip | 41.7% | 58.3% | 15.7% | 84.3% |
| Services | 100.0% | | 100.0% | |
| Meters | 100.0% | | 100.0% | |
| Street Lighting | 100.0% | | 100.0% | |
| Customer Accounting | 100.0% | | 100.0% | |

**Table 4**
**Impacts by Customer Class Due to Change to Minimum System Method**
**Total Revenue Requirement**

| | Residential | | Commercial | | Industrial | | Newfoundland Power | | Other | |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** | **Delta $** | **Delta %** |
| Island Interconnected | $70,743 | 0.2% | -$80,662 | -0.5% | $0 | 0.0% | $0 | 0.0% | $9,919 | 1.1% |
| Island Isolated | $578 | 0.0% | -$773 | 0.0% | $0 | 0.0% | $0 | 0.0% | $195 | 0.2% |
| Labrador Isolated | $6,254 | 0.1% | -$7,095 | -0.1% | $0 | 0.0% | $0 | 0.0% | $840 | 0.4% |
| L'Anse au Loup | $4,333 | 0.2% | -$5,251 | -0.6% | $0 | 0.0% | $0 | 0.0% | $919 | 2.5% |
| Labrador Interconnected | -$29,858 | -0.4% | $34,033 | 0.9% | -$17 | 0.0% | $0 | 0.0% | -$4,158 | -2.4% |
| Total | $52,050 | 0.1% | -$59,747 | -0.2% | -$17 | 0.0% | $0 | 0.0% | $7,714 | 0.5% |

**NEWFOUNDLAND & LABRADOR HYDRO**
**2004 Forecast Cost of Service**
**Functionalization & Classification Ratios**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Production | | Rural Prod & | Distribution | | | | | | | | | | | Specifically |
| Line | | Total | Production | & Transmission | Transmission | Transmission | Substations | Primary Lines | | Line Transformers | | Secondary Lines | | Services | Meters | Street Lighting | Accounting | Assigned |
| No. | Description | Amount | Demand | Energy | Demand | Demand | Demand | Demand | Customer | Demand | Customer | Demand | Customer | Customer | Customer | Customer | Customer | Customer |
| | | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) |
| | **Distribution** | | | | | | | | | | | | | | | | | |
| 28 | Substation Structures & Equipment | | | | | | 100% | | | | | | | | | | | |
| 29 | Land & Land Improvements - by Sub-function: | | | | | | | | | | | | | | | | | |
| 30 | Primary | 85% | | | | | | 84.4% | 15.7% | | | | | | | | | |
| 31 | Secondary | 15% | | | | | | | | | | 84.4% | 15.7% | | | | | |
| 32 | Land & Land Improvements | 100% | | | | | | 71.7% | 13.3% | | | 12.7% | 2.3% | | | | | |
| 33 | Poles - by Subfunction: | | | | | | | | | | | | | | | | | |
| 34 | 3 phase - Primary | 41.2% | | | | | | 58.9% | 41.1% | | | | | | | | | |
| 35 | Other Primary | 36.4% | | | | | | 58.9% | 41.1% | | | | | | | | | |
| 36 | Secondary | 22.4% | | | | | | | | | | 58.9% | 41.1% | | | | | |
| 37 | Poles | 100% | | | | | | 45.7% | 31.9% | | | 13.2% | 9.2% | | | | | |
| 38 | Primary Condctr & Equip | 100% | | | | | | 84.4% | 15.7% | | | | | | | | | |
| 39 | Submarine Conductor | 100% | | | | | | 100.0% | | | | | | | | | | |
| 40 | Transformers | 100% | | | | | | | | 73.0% | 27.0% | | | | | | | |
| 41 | Secondary Condctr & Equip | 100% | | | | | | | | | | 84.4% | 15.7% | | | | | |
| 42 | Services | 100% | | | | | | | | | | | | 100.0% | | | | |
| 43 | Meters | 100% | | | | | | | | | | | | | 100.0% | | | |
| 44 | Street Lighting | 100% | | | | | | | | | | | | | | 100.0% | | |
| 45 | Customer Accounting | 100% | | | | | | | | | | | | | | | 100.0% | |

**NEWFOUNDLAND POWER INC.**

**2001 MINIMUM SYSTEM ANALYSIS**

# NEWFOUNDLAND POWER INC.

## MINIMUM SYSTEM ANALYSIS



The minimum system analysis is based on two components

- Poles and Fixtures
- Conductors

**Minimum System Costs for Poles and Fixtures (Urban or Rural)**

| | | | |
|---|---|---|---|
| A | Estimated number of NP distribution line poles[1] | 215,631 | |
| B | Estimated cost of minimum system pole[2] | $755 | per pole |
| C | Estimated number of NP & NTC joint use distribution line poles[1] | 250,555 | |
| D | Estimated cost of minimum system pole structure[2] | $79 | |
| E | Total Distribution poles & fixtures account inflated to 2001 dollars[3] | $444,482,522 | |
| F | Minimum System Pole Costs (Line A times Line B) | $162,801,405 | |
| G | Minimum System Pole Structure Costs (Line C times Line D) | $19,793,845 | |
| | % Minimum System (classified as a Customer Cost) (Line (F+G) / Line E) | 41.08% | |

**Minimum System Costs for Conductor (Assuming Urban Constuction)**

| | | | |
|---|---|---|---|
| H | Estimated number of feet of conductor[4] | 52,325,260 | ft. |
| I | Estimated cost of minimum system conductor[2] | $0.87 | /ft. |
| J | Total distribution conductor account inflated to 2001 dollars[3] | $210,627,955 | |
| K | Minimum System Costs (H X I) | $45,522,977 | |
| | % Minimum System (classified as a Customer Cost) (Line K / Line J) | 21.61% | |

**Minimum System Costs for Conductor (Assuming Rural Constuction)**

| | | | |
|---|---|---|---|
| L | Estimated number of feet of conductor[4] | 52,325,260 | ft. |
| M | Estimated cost of minimum system conductor[2] | $0.63 | /ft. |
| N | Total distribution conductor account inflated to 2001 dollars[3] | $210,627,955 | |
| O | Minimum System Costs (L X M) | $32,964,914 | |
| | % Minimum System (classified as a Customer Cost) (Line O / Line N) | 15.65% | |

# NEWFOUNDLAND POWER INC.



**Summary of Results**

| | | |
|---|---|---|
| | Minimum System Costs | |
| | Poles and Fittings - Urban ( Line F + Line G ) | $182,595,250 |
| | Conductors - Urban ( Line K ) | $45,522,977 |
| | Total Minimum System - Urban | $228,118,227 |
| | Poles and Fittings - Rural ( Line F + Line G ) | $182,595,250 |
| | Conductors - Rural ( Line O ) | $32,964,914 |
| | Total Minimum System - Rural | $215,560,164 |
| P | Weighted Minimum System assuming 25% Urban, 75% Rural [5] | $218,699,680 |
| Q | Total Distibution Poles, Fixtures and Conductors | $655,110,476 |
| | % of Conductor Poles and Fittings Associated with Minimum System ( P / Q ) | 33.38% |
| | **Say** **Customer** | **33%** |
| | **Demand** | **67%** |

NOTES:
1- See Schedule 5
2 - See Schedule 2.
3 - Inflated to 2001 using Handy Whitman Index, results provided in Schedule 4.
4 - See Schedule 3
5 - Estimated Split

# NEWFOUNDLAND POWER INC.



## MINIMUM SYSTEM UNIT COST ESTIMATES

Based on Construction Estimates used for the 2002 CIAC Costing Tables.

### Estimated Cost of Minimum Size Pole (35 foot)

| Description | Quantity | Labour[1] | Material[1] |
|---|---|---|---|
| 35' Pole | 1 | $385.00 | $204.80 |
| Sub Total | | 385.00 | 204.80 |
| Total Material & Labour | | | $589.80 |
| Engineering and Supervision (Labour Only) | 25% | | 96.25 |
| Sub Total | | | 686.05 |
| General Expenses Capitalized | 10% | | 68.61 |
| Total | | | $754.66 |

### Estimated Cost of Minimum Size Pole Structure

| Description | Quantity | Labour[1] | Material[1] |
|---|---|---|---|
| Structure AL | 1 | 38.67 | 23.58 |
| Sub Total | | 38.67 | 23.58 |
| Total Material & Labour | | | $62.25 |
| Engineering and Supervision (Labour Only) | 25% | | 9.67 |
| Sub Total | | | 71.92 |
| General Expenses Capitalized | 10% | | 7.19 |
| Total | | | $79.11 |

# NEWFOUNDLAND POWER INC.



## ESTIMATED COST OF MINIMUM SIZE CONDUCTOR (URBAN)

Based on 150 ft. Spans of #8 Bare Copper Wire single phase extension.

| Description | Quantity | Labour[1] | Material[2] |
|---|---|---|---|
| #8 Bare Copper Wire | per foot | $0.52 | $0.14 |
| Sub Total | | 0.52 | 0.14 |
| Total Material & Labour | | $0.66 | |
| Engineering and Supervision (Labour Only) | 25% | 0.13 | |
| Sub Total | | 0.79 | |
| General Expenses Capitalized | 10% | 0.08 | |
| Total | | $0.87 | |

## ESTIMATED COST OF MINIMUM SIZE CONDUCTOR (RURAL)

Based on 250 ft. spans of 1/O AASC Primary

| Description | Quantity | Labour[1] | Material[1] |
|---|---|---|---|
| 1/0 AASC Primary | per foot | $0.31 | $0.186 |
| Sub Total | | 0.31 | 0.186 |
| Total Material & Labour | | $0.50 | |
| Engineering and Supervision (Labour Only) | 25% | 0.08 | |
| Sub Total | | 0.57 | |
| General Expenses Capitalized | 10% | 0.06 | |
| Total | | $0.63 | |

NOTES:

1 - Material and Labour cost from 2002 CIAC Costing Manual.
2 - Based on a quote for one kilometre of #8 Bare Copper Conductor

## NEWFOUNDLAND POWER INC.



### ESTIMATED CONDUCTOR MILES

The number of conductor miles is estimated in two components: overhead estimate and underground estimate. The overhead portion is estimated based the number of distribution pole miles. The underground portion is based on the installed feet of cable recorded in plant records.

**Estimated number of feet of minimum system conductor required.**

| | | |
|---|---|---|
| Distribution pole miles[1] | 4,893 | miles |
| Distribution underground miles[2] | 62 | miles |
| Total Number of Feet of Minimum System Conductor | | |
| Overhead (5280 ft/ mile * 2 conductors for single phase) | 51,669,062 | ft. |
| Underground (5280 ft/ mile * 2 conductors for single phase) | 656,198 | ft. |
| Total | 52,325,260 | ft. |

NOTES:

1 - Latest available estimate based on number of poles times an average span length (2001)

2 - Estimated from drawings and field information in 1992 & 1993. The number has not changed significantly since that time.

**NEWFOUNDLAND POWER INC.**



**ESTIMATED REPLACEMENT VALUE OF CONDUCTORS, POLES AND FITTINGS FOR DISTRIBUTION**

The Schedule provides the current dollar estimate of the Plant in Service as determined for insurable property purposes. The portions of Distribution Conductors, Poles and Fittings associated directly with Street Light Plant are removed in the calculations below.

2001 Value of Plant taken from Insurable Property Calculation for December 31, 2001.

**Distribution Poles (Includes Service Poles)**

| | |
|---|---|
| Poles and Fixtures - Up to 35 feet | $113,417,063 |
| Poles and Fixtures - Over 35 feet | $345,278,566 |
| **Subtotal** Replacement Value Distribution Poles and Fixtures | $458,695,629 |
| | |
| Wood Poles dedicated to Street Lights - Up to 35 feet[1] | $3,514,332 |
| Wood Poles dedicated to Street Lights - Over 35 feet[1] | $10,698,775 |
| **Subtotal** Replacement Value Street Lighting | $14,213,107 |
| | |
| **Estimated Replacement Value of Distribution Plant** | **$444,482,522** |

**Distribution Conductors (Includes Service Wires)**

| | |
|---|---|
| Bare Copper Overhead Conductor | $7,360,974 |
| W/P Copper Overhead Conductor | $14,687,673 |
| Bare Aluminum Overhead Conductor | $137,804,233 |
| W/P Aluminum Overhead Conductor | $35,406,846 |
| Aerial Cable O/H Conductor | $1,580,276 |
| Duplex overhead conductor | $3,907,014 |
| Underground Cables | $24,271,683 |
| **Subtotal** Replacement Value Distribution Conductors | $225,018,699 |

**Less Street and Area Lighting Conductor**

| | |
|---|---|
| Duplex overhead conductor[2] | $3,907,014 |
| Underground Cables[1] | $10,483,730 |
| **Subtotal** Replacement Value Street and Area Lighting Conductor | $14,390,744 |
| | |
| **Estimated Replacement Value of Distribution Conductor** | **$210,627,955** |

NOTES:
1 - Street Light Portion based on a % of total plant as determined on Schedule 5.
2 - All duplex assumed to be Street Lighting.

## NEWFOUNDLAND POWER INC.



### ESTIMATED PERCENTAGE OF PLANT ASSOCIATED WITH STREET LIGHTING

**Poles under 35' (Includes Service Poles)**

| | QTY | Cost |
|---|---|---|
| Street and Area Lighting wood poles[1] | 7,440 | $3,720,308 |
| Total wood poles[2] | 223,071 | $120,064,456 |
| % of costs related to Street and Area Lighting | | 3.10% |

**Underground Street and Area Lighting Conductor**

| | |
|---|---|
| Total Cost Underground Conductor[2] | $15,166,986 |
| Total Cost Underground Street and Area Lighting Conductor[2] | $6,551,115 |
| % of costs related to Street and Area Lighting | 43.19% |
| Total number of NTC poles joint use with NP[3] | 34,924 |

Notes:
1. Analysis of Street Lighting Plant Records
2. From 2001 Plant Records
3. As of December 31, 2001

**NEWFOUNDLAND POWER INC.**

**2001 DISTRIBUTION TRANSFORMER ZERO INTERCEPT ANALYSIS**

## ZERO INTERCEPT ANALYSIS



The zero intercept analysis is based on a regression analysis of the costs of the transformers below 50 kVA. The regression is based on two dependent variables, Quantity and kVA size.

**List of the Current Value (2001) of Transformers 50 kVA and Less**

| Transformer size KVA | Quantity | Total 2001 Value[2] | Unit Cost | Quantity % of Total |
|---|---|---|---|---|
| 5 | 2,095 | $863,069 | $412 | 3.74% |
| 7.5 | 143 | 77,487 | 542 | 0.26% |
| 10 | 8,395 | 6,621,289 | 789 | 14.98% |
| 15 | 3,208 | 2,056,539 | 641 | 5.72% |
| 20 | 17 | 14,803 | 871 | 0.03% |
| 25 | 15,770 | 16,543,577 | 1,049 | 28.13% |
| 30 | 6 | 8,599 | 1,433 | 0.01% |
| 37.5 | 3,634 | 3,432,944 | 945 | 6.48% |
| 40 | 5 | 7,390 | 1,478 | 0.01% |
| 45 | 2 | 4,151 | 2,075 | 0.00% |
| 50 | 13,162 | 19,748,014 | 1,500 | 23.48% |
| 75 | 6,301 | 12,366,616 | 1,963 | 11.24% |
| 100 | 1,722 | 4,236,006 | 2,460 | 3.07% |
| 150 | 62 | 192,527 | 3,105 | 0.11% |
| 167 | 186 | 673,348 | 3,620 | 0.33% |
| 200 | 14 | 67,115 | 4,794 | 0.02% |
| 225 | 33 | 208,762 | 6,326 | 0.06% |
| 250 | 46 | 235,981 | 5,130 | 0.08% |
| 300 | 238 | 2,237,889 | 9,403 | 0.42% |
| 333 | 3 | 30,087 | 10,029 | 0.01% |
| 500 | 249 | 3,303,811 | 13,268 | 0.44% |
| 600 | 8 | 93,602 | 11,700 | 0.01% |
| 750 | 118 | 2,102,280 | 17,816 | 0.21% |
| 1000 | 27 | 639,488 | 23,685 | 0.05% |
| 1250 | 1 | 27,216 | 27,216 | 0.00% |
| 1500 | 21 | 620,986 | 29,571 | 0.04% |
| 2500 | 1 | 40,266 | 40,266 | 0.00% |
| Padmounts | 590 | 1,702,318 | | |
| Mountings & Pads | | 658,104 | | |
| Totals | 56,057 | 78,814,263 | | |

Regression Coeficients:

| | | |
|---|---|---|
| Unit Size | 28.5364 | |
| Quantity | (0.0119) | |
| Constant | $377.84 | (zero intercept) |

| | | | |
|---|---|---|---|
| Cost of Zero Intercept Transformer | $377.84 | | |
| Total Transformer Quantity | 56,057 | | |
| Total Transformer Plant[2] | $78,814,263 | | |
| Customer Component (56,057 * $377.84) | $21,180,839 | **27%** | **Customer** |
| Demand Component ( $78,814,263 - $21,180,839) | $57,633,424 | **73%** | **Demand** |

Notes: 1. From 2001 Plant Records
2. 2001 Value of Plant taken from Insurable Property Calculation for 2001

**NEWFOUNDLAND POWER INC.**

**OUTPUT of REGRESSION ANALYSIS**



| *Regression Statistics* | |
|---|---|
| Multiple R | 0.884618641 |
| R Square | 0.78255014 |
| Adjusted R Square | 0.728187675 |
| Standard Error | 261.9779344 |
| Observations | 11 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 2 | 1975934.097 | 987967.0487 | 14.395045 | 0.002235818 |
| Residual | 8 | 549059.5049 | 68632.43811 | | |
| Total | 10 | 2524993.602 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* |
|---|---|---|---|---|
| Constant | 377.8446847 | 163.0984692 | 2.316666039 | 0.0491747 |
| Unit Size | 28.53641056 | 5.318470433 | 5.365529605 | 0.0006732 |
| Quantity | -0.01193249 | 0.014703282 | -0.81155284 | 0.4405242 |

RESIDUAL OUTPUT

| *Observation* | *Predicted Y* | *Residuals* | *Standard Residuals* |
|---|---|---|---|
| 1 | 495.5281699 | -83.56191848 | -0.356614252 |
| 2 | 590.1614178 | -48.29287358 | -0.206097793 |
| 3 | 563.0355326 | 225.6826822 | 0.963138021 |
| 4 | 767.6114136 | -126.5456511 | -0.540054411 |
| 5 | 948.3700436 | -77.59955569 | -0.331168886 |
| 6 | 903.0795737 | 145.9741519 | 0.622968738 |
| 7 | 1233.865407 | 199.3741723 | 0.850862122 |
| 8 | 1404.59741 | -459.9239035 | -1.962801018 |
| 9 | 1519.241445 | -41.17731842 | -0.175730989 |
| 10 | 1661.959295 | 413.2990734 | 1.763821875 |
| 11 | 1647.609773 | -147.228859 | -0.628323408 |

# EXHIBIT E

# SUPPORTING DOCUMENTATION, ALLOCATION OF DEMAND RELATED DISTRIBUTION COSTS

**NEWFOUNDLAND AND LABRADOR**
**BEFORE THE**
**BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

**IN THE MATTER OF the Public Utilities Act, (R.S.N. 1990, Chapter P-47 (the "Act")),**

**AND**

**IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for approvals of: (1) Under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to its Retail Customers, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the Act, Its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the Act, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the Act, its 2002 Capital Budget.**

# Pre-filed Evidence

# of

# Dr. John W. Wilson

**July 31, 2001**

**NEWFOUNDLAND AND LABRADOR**
**BEFORE THE**
**BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

**IN THE MATTER OF the Public Utilities Act, (R.S.N. 1990, Chapter P-47 (the "Act")),**

**AND**

**IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for approvals of: (1) Under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to its Retail Customers, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the Act, Its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the Act, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the Act, its 2002 Capital Budget.**

# DIRECT EVIDENCE OF

# DR. JOHN W. WILSON

## I. QUALIFICATIONS AND INTRODUCTION

**Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia, 22209.

grid to achieve optimal dispatch. Hence, the transmission grid helps reduce energy costs and this should be recognized in the classification of transmission costs. This causality is not adequately recognized in Hydro's classification of transmission costs, which attributes virtually all grid costs (i.e., with the exception of lines used exclusively to connect remote generation) to peak demand.

If a generation plant is located near the source of fuel, rather than near the load center, the cost of fuel is reduced, but transmission costs are increased. The extreme example of this is a hydroelectric plant that must be located at a water source, and the power generated there must be transmitted over high-voltage transmission to load centers and integrated on a transmission network with power production from other locations. The result is a savings on energy-related generating costs at the expense of greater transmission costs. In Hydro's case, substantial transmission investment and expense is clearly related to both the transport and network integration of less costly energy from remote locations rather than to simply meet peak demand. The important network integration aspect of these facilities would be better recognized by using load factors to assign a portion of all transmission plant to energy.

**<u>Hydro's Allocation of Distribution Demand Costs</u>**

A related issue is Hydro's proposal to allocate all non-customer distribution system costs on the basis of coincident peak demand. The coincident peak method basically allocates all costs classified as demand-related to customer classes in proportion to each class' contribution to the system coincident peak or peaks. The rationale for this approach is that the required capacity is determined by the maximum coincident demand to be placed on the system. However, this rationale does not hold where the cost level is not determined by system coincident peak demand. In the case of local distribution networks, it is local loads, which often vary from the system coincident peak, that determine plant requirements. Therefore, a noncoincident demand allocator for distribution capacity is generally thought to be more reasonable for cost allocation.

Since each class may experience its own peak at a different time than that at which the system peak occurs, the sum of the non-coincident class peaks typically will exceed the system coincident peak by a significant margin. This inter-class diversity benefits the system in the sense that the utility need only install sufficient generation capacity to meet the diversified (i.e., coincident) peaks of the several classes. But this is not equally true with respect to distribution plant requirements. A non-coincident peak demand allocation method assigns demand-related costs to customer classes in proportion to each class' share of the sum of all class non-coincident peaks ("NCP"). Thus, in contrast to the coincident peak method, this procedure distributes the interclass diversity benefits generated by the off-peak consumption characteristics of customers in any given class. Compared to the coincident peak approach, classes which have peaks coincident with the system would be assigned a smaller share of total NCP demand-related costs, and classes with high diversity would be assigned a larger portion of these costs.

Although the use of NCPs in determining a class' responsibility for demand-related generation and transmission investments may be questionable, the use of NCPs to allocate demand-related distribution costs is more reasonable. Demand-related distribution facilities are typically installed to meet each local areas' loads, rather than demands at the time of the system coincident peak. However, class contributions to these local loads are not generally measured with precision, and therefore some available proxy must be used. It is typically argued that non-coincident class peaks are a better proxy for the true cost-causative factor in this setting, because portions of the distribution system are frequently built to serve only customers in a single customer class (e.g., a distribution system for a new residential development). Sometimes the sum of the individual customer non-coincident maximum (billing) demands is used as the proxy for demands placed on local distribution systems, and demand-related distribution costs and investments are allocated on the basis of a class' share of these demands. Neither is an ideal proxy for the class contributions to local area peak demands, but either is likely to be preferable to using class contributions to the system coincident peak for purposes of allocating distribution demand costs.