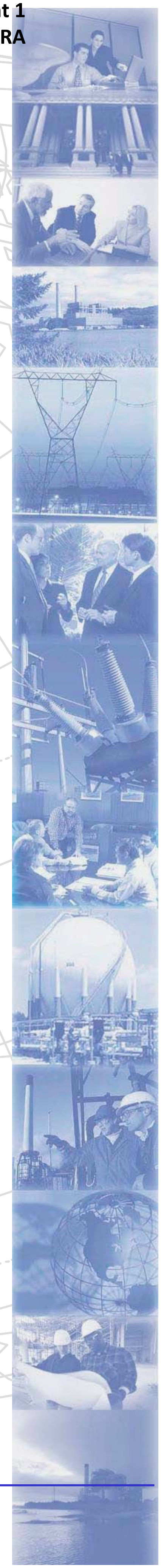
Q. **Re: NLH Evidence, Section 2, page 2.43, lines 5-10**

Please provide a detailed description of the regulatory practices governing the NP generation credit.

A. Please see attached "Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation" report, filed with Hydro's 2006 GRA. The report includes a history of the treatment of NP's generation credit.

Board Order No. P.U. 8(2007), page 22, discussed the resolution of this matter. The following extract provides a summary of the current practice.

> *In the November 23, 2006 Agreement on Cost of Service, Rate Design and Other Issues the parties advised that agreement had been reached on the outstanding cost of service issues relating to customer owned generation and specifically assigned charges. With respect to customer owned generation the Agreement proposed that:*
>
> *"Consistent with recommendations in Exhibit RDG-2 (Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation), NP will continue to receive a credit for its hydro and thermal generation in the cost of service study as proposed in the Application with two modifications, as follows:*
>
> *a. the impact on system load factor of the existing thermal credit mechanism and its resulting change in cost classification will no longer form part of the compensation;*
>
> *and*
>
> *b. compensation for transmission relating to NP thermal will be discontinued such that NP's common transmission cost allocation is not reduced."*



Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation

Prepared for

Newfoundland & Labrador Hydro

February 3, 2006

Prepared by

Shaw® Stone & Webster Management Consultants, Inc.

TABLE OF CONTENTS

Section	*Description*	*Page*
1	**INTRODUCTION**	**1**
2	**BACKGROUND**	**2**
2.1	THE EXISTING CREDIT MECHANISM	2
2.1.1	Genesis	2
2.1.2	Structure	3
2.2	POSITION OF THE PARTIES	3
2.2.1	The Industrial Customers' Position	3
2.2.2	EES Consulting	4
2.2.3	The Consumer Advocate's Position	4
2.2.4	NP's Position	4
2.2.5	Hydro's Position	4
3	**STANDARDS FOR DESIGN OF COMPENSATION MECHANISM**	**5**
4	**THE ISSUES**	**6**
4.1	HYDRAULIC CREDIT MECHANISM	6
4.1.1	Hydraulic Generation Compensation Through a Credit	6
4.1.2	Fairness	7
4.1.3	Difference Between NP's Hydraulic Forecast and Hydraulic Credit	7
4.1.4	Appropriate Value for NP Hydraulic Generation	8
4.2	THERMAL CREDIT MECHANISM	8
4.2.1	Value of NP Thermal Generation to Hydro's Island Interconnected System	8
4.2.2	Lack of Transparency with the Existing Thermal Credit Mechanism	9
4.2.3	The Appropriateness of the Credit Affecting System Load Factor	10
4.2.4	The Appropriateness of the Credit for Transmission Costs	11
4.2.5	Appropriate Value for NP Thermal Generation	11
5	**NEWFOUNDLAND POWER'S PERSPECTIVE**	**18**
6	**NEWFOUNDLAND AND LABRADOR HYDRO'S PERSPECTIVE**	**20**
7	**RATE DESIGN CONSIDERATIONS**	**21**
8	**SUMMARY OF FINDINGS AND RECOMMENDATIONS**	**22**
9	**EXHIBITS**	**24**

LIST OF TABLES

Table *Description* *Page*

Table 1: Existing COS Credit Mechanism 3
Table 2: Notional Payment - Existing COS Credit Mechanism 9
Table 3: Notional Payment - Excluding System Load Factor Impacts 10
Table 4: Notional Payment - Excluding System Load Factor and Transmission Cost Impacts 11
Table 5: Value of NP Thermal Generation Assets 13
Table 6: Summary - Comparison of NP Thermal Generation Values 16

LIST OF EXHIBITS

Exhibit *Description* *Page*

Exhibit 1: Customer Impacts – COS Analysis with NP Generation Credit Removed 25
Exhibit 2: COS NP Generation Credit Unit Costs 26
Exhibit 3: Customer Impacts - NP Generation Credit 27
Exhibit 4: Equivalency of a Separate Payment to NP with the Existing Credit Mechanism 28
Exhibit 5: Capacity Unit Costs 29
Exhibit 6: Value of NP and IC Generation Assets – Generation Analysis 30
Exhibit 7: Value of NP and IC Generation Assets - Transmission Analysis 31
Exhibit 8: Summary of Newfoundland Power's Thermal Generation Units and Age 34

1 Introduction

This report was prepared by Stone & Webster Management Consultants, Inc. (Stone & Webster Consultants) in response to the request by Newfoundland and Labrador Hydro (Hydro) to perform an independent study regarding an appropriate treatment of Newfoundland Power (NP) generation. The need for the study is the result of the Board of Commissioners of Public Utilities (the Board) Order No. P.U. 14 (2004), in which the Board accepted Hydro's treatment of NP's hydraulic and thermal generation in the cost of service (COS) study, but directed Hydro:

> "… to commission an independent study, to be filed with its next general rate application, of the treatment of NP's generation. This study should assess the value of NP's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design."

In order to address the Board's request, this review has investigated the treatment of generation from a planning, operating, and financial perspective by assessing how Hydro includes non-Hydro owned generation in the long term resource plans for the system as a whole, identifying the operational actions taken by Hydro with respect to these resources, and evaluating the financial treatment from a COS perspective.

In performing this review, Stone & Webster Consultants worked with Hydro personnel and requested specific computer-modeling cases to be run. We also interviewed NP personnel with respect to what they perceived as relevant considerations in valuing their generation.

2 Background

NP is Hydro's largest customer on the Island Interconnected system, historically accounting for approximately 80 percent of Hydro's Island Interconnected peak demand. NP maintains 94.6 MW of hydraulic generation and 50.9 MW of thermal generation consisting of gas turbines and diesel units. In the 2004 test year, NP's forecast system load of 1,162.3 MWh was projected to be met with 81.6 MW from its hydraulic generation and the balance from Hydro's generation resources. NP's thermal units are generally used to provide emergency generation, both locally and for the interconnected grid, and to facilitate local maintenance. They are typically not run at the time of Hydro's system peak, but are assumed to be available. However, Hydro may ask NP to run its thermal generation and to maximize its hydraulic generation when needed to meet system requirements. When NP's thermal generation is run at Hydro's request, Hydro pays NP for the fuel consumed.

Hydro compensates NP for the right to call on its generation through a credit mechanism in Hydro's COS. In the last two general rate applications, the mechanism has been a subject of debate among the parties. In the case of NP's thermal generation, questions arose as to whether it provided a benefit to Hydro or only to NP and whether NP should receive a credit for its units, since they do not typically operate during Hydro's system peak. The credit for NP's hydraulic generation has been called into question with regard to the extent to which NP's test year hydraulic forecast differed from actual.

Hydro is responsible for planning to ensure there is sufficient generation to meet the Island's load requirements and as part of its planning relies on the availability of the hydraulic and thermal units owned by NP and the hydraulic units owned by the Industrial Customers (IC). Both parties are treated similarly within the planning process in this way.

2.1 The Existing Credit Mechanism

2.1.1 Genesis

Prior to 1977, Hydro compensated NP for its generation based on the net book value of its thermal generating units. In a 1977 report to the Government, the Board concluded that NP's thermal generating plant was used and useful to Hydro's system and recommended that the capacity of NP's generating units should be deducted from NP's demand in Hydro's COS. The following excerpt from the report provides the Board's rationale:

> "The Board recognizes that deducting the capacity of these thermal units from NLP's demand gives NLP customers credit for value of service rather than cost of service based on net book value of the units but we consider this to be justified otherwise Hydro's industrial customers would benefit from depreciation paid by NLP's customers over the past years on NLP's thermal units. Furthermore Hydro will not be required to pay a capacity charge to NLP."

At that time, NP's resources that were included in the credit included two gas turbines, plus the Southside Steam Plant which was able to supply firm energy. Diesel, which was considered to firm-up hydraulic, and NP's mobile gas turbine were not included.

The Board's 1977 recommendation formed the basis for the existing credit mechanism.

2.1.2 Structure

Under the existing credit mechanism, NP's forecast native load is reduced by NP's hydraulic and thermal generation capacity, less an allowance for system reserve. **Table 1** illustrates this process. This reduced load is then used to develop allocation factors for the demand component of generation and transmission costs in Hydro's COS. The methodology uses NP's forecast native load[1] and subtracts generation credits.

Table 1: Existing COS Credit Mechanism

2004 Final Test Year (kW)			
	Capacity	Less Reserve @ 16 %	Final Test Year P.U. 14
Coincident Peak (CP):			
NP Forecast Load to be Served by Hydro			1,080,700
Plus NP Hydraulic Generation			81,600
NP Forecast Native Load			1,162,300
Less Credits:			
Hydraulic Generation	(94,620)	13,070	(81,550)
Gas Turbine & Diesel	(50,900)	7,000	(43,900)
Total Credits	(145,520)	20,070	(125,450)
Net CP for COS			1,036,850

There are several observations to be made with respect to the existing mechanism:

1. The mechanism effectively credits only NP's net thermal capacity, since NP forecasts its hydraulic generation, thus reducing the load served by Hydro. The mechanism will also reflect an adjustment to the extent that NP's hydraulic forecast differs from its hydraulic capacity net of reserve.

2. The mechanism credits NP for its thermal generation based on the average embedded cost of Hydro's Island Interconnected generation and transmission costs.

3. The credit mechanism also adjusts the Island Interconnected system load factor, which shifts costs from demand to energy.

2.2 Position of the Parties

In Hydro's last general rate application, the issue of the treatment of NP's generation was the subject of considerable discussion. The position of each of the parties is summarized below.

2.2.1 The Industrial Customers' Position

While the IC support the recognition of NP's hydraulic generation in the COS, they recommended that the hydraulic credit should only reflect the peak capacity NP provides to the system based on economic dispatch to maximize energy output.

[1] Native load is the total Newfoundland Power load, which is supplied both through power purchases from Hydro and its own generation sources.

The IC believe that in contrast to NP's hydraulic generation, their thermal generation plays no role in meeting the system energy requirements. They argue that NP's thermal generation is designed to meet emergency needs in specific service areas; is primarily used as backup generation support at the end of long radial lines at Burin/Port aux Basques; and only incidentally provides some peaking capacity to the system. The IC submit that NP's thermal generation is of no use to them.

The IC argued that as a result of the treatment of NP's thermal generation under the existing mechanism, the IC and Hydro's rural customers pay for 60 percent of NP's cost of its peaking generation[2], despite making up only 20 percent of the Island peak.

2.2.2 EES Consulting

EES Consulting[3] (EES) addressed the demand credit within the context of the proposed demand and energy rate for NP. They recommended a generation tariff in lieu of the generation credit to ensure that financial transactions corresponded with the operational flow of energy, thereby making it more transparent and robust. If this option were not adopted, EES recommended that Hydro unbundle the application of the credit in its COS 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.

2.2.3 The Consumer Advocate's Position

The Consumer Advocate (CA) agreed with the views put forth by the IC and EES and recommended that generation be split between generation capacity for the entire system and NP distribution capacity for localized areas. The CA further recommended that Hydro be directed to commission an independent study of the treatment of NP generation in order to assess the value of this generation to the system and to make recommendations on how the generation should be accounted for, both operationally and financially in the COS and rate design.

2.2.4 NP's Position

NP argued that its thermal as well as its hydraulic generation play an important role in Hydro's generation planning and system operations and that the peak demands used in Hydro's COS should be net of the capacity NP makes available to the Island Interconnected system.

2.2.5 Hydro's Position

Hydro filed with the Board a report by its System Planning department which concluded that NP's thermal generation has value with regard to generation planning for the Island Interconnected system.

As Hydro's consultant, Stone & Webster Consultants agreed there was an apparent anomaly in the customer impacts resulting from the current credit mechanism.

[2] Based on a revenue requirement to NP's customers of $1,691,000, as reviewed by the Board in NP's 2003 GRA (NLH 2003 GRA, RFI IC-187 NP).
[3] Witness called by Board hearing counsel

3 Standards for Design of Compensation Mechanism

To assist in evaluating alternative mechanisms with respect to each other and to the existing mechanism, Stone & Webster Consultants has identified standards for measurement, which include:

- Fairness, or equitability among customer groups;
- Transparency;
- Relationship to cost causation;
- Conservation – demand and energy;
- Efficiency incentives[4]; and
- Practical implications.

[4] Efficiency incentives refer to maintaining NP's incentive to operate its generation resources in an optimal fashion.

4 The Issues

NP's hydraulic generation runs at the time of the system peak, clearly demonstrating that it has value to the Island Interconnected system. However, the value of NP's thermal generation is more elusive, since Hydro seldom calls on these units to be run during potential system peak hours. This distinct difference between hydraulic and thermal generation warrants separate consideration.

Based on the concerns raised by the parties, Stone & Webster Consultants has identified the following issues:

1. Hydraulic credit mechanism
   - 1.1 Hydraulic generation compensation through a credit
   - 1.2 Fairness
   - 1.3 Difference between NP's hydraulic forecast and hydraulic credit
   - 1.4 Appropriate value for NP hydraulic generation

2. Thermal Credit Mechanism
   - 2.1 Whether NP thermal generation has value to Hydro's Island Interconnected system
   - 2.2 Lack of transparency with the existing credit mechanism
   - 2.3 Appropriateness of the credit affecting system load factor
   - 2.4 Appropriateness of the credit for transmission costs
   - 2.5 Appropriate value for NP thermal generation

4.1 Hydraulic Credit Mechanism

4.1.1 Hydraulic Generation Compensation Through a Credit

The existing credit for NP's hydraulic generation provides compensation to NP based on a set value, regardless of the actual generation at the time of Hydro's system peak. This credit is accompanied by an obligation on the part of NP to demonstrate the capability of its combined hydraulic and thermal generation at some point during the winter season, at least to the value it receives as a total credit. This credit mechanism enables NP to operate its hydraulic generation to maximize energy throughput and reduce the possibility of spillage, without the constraint of having to anticipate the exact timing of Hydro's system peak. Furthermore, the existing hydraulic credit mechanism supports the original spirit of the demand and energy rate, which was to provide NP with an incentive to manage its native load, rather than its net load. From Hydro's perspective, a credit mechanism removes the potential for over or under collection of NP's share of Hydro's revenue requirement due to variances between forecast and actual customer hydraulic generation.

Recommendation: Stone & Webster Consultants recommends that Hydro's costing and billing to NP continue to reflect a set credit for its hydraulic generation, in conjunction with NP's continued obligation to demonstrate the capability of its combined hydraulic and thermal generation.

4.1.2 Fairness

For both NP and IC, cost allocation factors used in Hydro's COS reflect a reduction for customer hydraulic generation. In NP's case, the reduction is through a set credit value; for IC, the reduction is established based on their hydraulic forecasts, resulting in a lower Power on Order from Hydro.

If the IC exceed their Power on Order on an actual basis, they have access to interruptible power and generation outage power, neither of which has a demand charge. Their interruptible power cost is an energy charge based on Hydro's fuel costs.

In the case of NP, since the demand and energy rate under which it is served is generation-independent, if its actual hydraulic generation is less than the hydraulic credit at the time of the system peak it will not incur additional demand charges. NP, however, pays for all tail block energy at the rate of $0.047 which is based on the cost of fuel at Holyrood.

The IC must meet their Power on Order in each 15-minute interval. If their hydraulic generation is not available for a particular 15-minute interval, it will trigger the need to purchase generation outage power. However, if their hydraulic generation becomes available the next day, the water that has been stored can act to offset their firm energy rate of $0.027, but not their Power on Order purchases. NP does not have a similar 15-minute requirement for its hydraulic generation. If its hydraulic generation is not available at any point, but becomes available the next day, the water that has been stored can act to offset its purchases made during the previous day at its tail block rate, with no financial consequence. The operational incentives for NP to have its generation on during peak periods are therefore not as stringent as for the IC, who must continually strive to operate their hydraulic generation so as to not exceed their Power on Order. However, a spill, which may result due to a hydraulic generation outage, eliminates the opportunity for either IC or NP to offset their firm power rate. In such a spill situation each pays a rate based on the cost of Holyrood fuel.

Finding: IC have more rigid conditions than NP regarding generation availability during peak periods. If conditions were placed on NP to ensure availability of NP generation, if called upon, during peak periods, then both customer classes would be served under more comparable conditions.

4.1.3 Difference Between NP's Hydraulic Forecast and Hydraulic Credit

IC's load forecast of requirements from Hydro is net of customer-owned forecast hydraulic generation. NP also forecasts its hydraulic generation, but the calculated credit, which incorporates a 16 percent reserve requirement, may be different. The IC have recommended that NP's hydraulic generation credit in the COS be the same as NP's forecast for hydraulic generation.

While Stone & Webster Consultants agrees that the IC recommendation may have merit insofar as the credit would reflect the hydraulic generation that NP believes it can provide, we believe that the existing credit mechanism, which costs NP based on its hydraulic capacity net of reserve, offers additional advantages.

- The calculated credit reflects a discount factor in the form of a reserve to recognize that no generation is available 100% of the time.

- The calculated credit based on capacity less an allowance for system reserve has regulatory precedent in Newfoundland.

- The reduction or the discount is representative of the generation mix on the Island Interconnected System[5].

- The calculated credit is independent of any financial implications that may otherwise influence a credit based on the hydraulic forecast. If the credit were to be based on NP's hydraulic generation forecast instead of a calculated amount, the onus would shift to the regulatory environment to ensure the reasonableness of NP's hydraulic generation forecast. For example, if NP's forecast were consistently low, this would guarantee NP's ability to meet it, but would cost NP's customers more.

- The terms of Hydro's demand and energy rate provide that NP must demonstrate on an annual basis that its generation is actually capable of delivering the capacity for which it receives credit. If, in a given year, NP's hydraulic forecast is less than the credit, but it demonstrates that its hydraulic and thermal capability is equal to or greater than the total credit, then it only receives the credit. However, if during the annual testing NP cannot demonstrate its total generation capability to the level of the credit, the credit will be reduced. Thus, the credit mechanism, together with the testing requirement, assures Hydro of NP's hydraulic capability and speaks to the IC concern of recognizing NP's forecast to the extent that its forecast is accurate in reflecting its diminished hydraulic capability.

Recommendation: The existing mechanism should continue to credit NP for its hydraulic generation based on capacity net of reserve, but any differences with respect to its hydraulic forecast should continue to be monitored.

4.1.4 Appropriate Value for NP Hydraulic Generation

Since NP's hydraulic generation is forecast to operate during the system peak, Hydro only needs to serve NP's native load net of its hydraulic generation. If NP did not own hydraulic generation, NP would be allocated a larger proportion of Hydro's embedded costs. Thus, NP hydraulic generation is effectively avoiding Hydro's average embedded demand costs[6], which is consistent with the treatment of IC generation as well as with traditional cost of service practice.

Recommendation: NP should continue to receive credit for its hydraulic generation based on Hydro's average embedded costs as it is consistent with principles of cost causation.

4.2 Thermal Credit Mechanism

4.2.1 Value of NP Thermal Generation to Hydro's Island Interconnected System

In assessing whether NP thermal generation has value to Hydro's system, Stone & Webster Consultants has relied on the report filed by Hydro's System Planning Department in response to Order No. P.U. 7 (2002), titled Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets (Planning Report).

[5] It is recognized that the system reserve that is applied to NP's hydraulic and thermal generation is subject to some variability at the time of Hydro's rate cases, depending on its generation mix and load shape, but is not expected to change so significantly as to affect the validity of its use in the credit mechanism.
[6] This includes generation and transmission demand costs, as well as system load factor impacts.

Under Hydro's planning criteria for the Island Interconnected System there needs to be sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) criteria of not greater than 2.8 hours per year. Table 3.3 in the Planning Report shows that based on Hydro's near-term capability requirements the effect of the removal of NP's thermal generating units would have advanced the timing of capacity deficits. This evidence shows that NP's thermal generation does indeed play a role in meeting forecast system requirements.

With respect to the IC position that NP thermal generation is of no benefit to the IC, Stone & Webster Consultants disagrees and supports Hydro's position as set forth in the Planning Report. That is, with respect to the value of generation, there are no locational limitations. The generation must be capable of delivering capacity and energy to the system and the system must be capable of utilizing that capacity when needed. NP's thermal generation meets these criteria.

Finding: Stone & Webster Consultants concludes that NP thermal generation has value to Hydro's Island Interconnected system and contributes to the benefit of all customers.

4.2.2 Lack of Transparency with the Existing Thermal Credit Mechanism

Exhibit 1 shows that the thermal credit in the COS provides a net decrease to NP of $855,900[7], with an attendant increase to IC and Rural of $633,429 and $222,471[8], respectively. However, through COS analysis, it has been shown that Hydro is effectively providing NP with a notional payment of $3.630 million. By virtue of the allocation process in the COS, 76 percent of this notional payment is allocated back to NP, resulting in a net cost allocation credit of $855,900. The derivation of these amounts is shown in **Exhibits 2 and 3**, and summarized in **Table 2**. A proof of the equivalency of a $3.6M separate payment with the existing credit mechanism is contained in **Exhibit 4**.

Table 2: Notional Payment - Existing COS Credit Mechanism

	Notional Payment	COS Allocation	Percent of Total (1)	Net Cost Impact
Newfoundland Power	3,630,018	2,774,118	76.4%	(855,900)
Island Industrial		633,429	17.4%	633,429
Rural Island Intercnctd		222,471	6.1%	222,471
		3,630,018	100.0%	0

(1) Includes customer demand cost allocation percentages plus the credit mechanism's effect on the system load factor.

As can be seen from **Table 2**, the IC and Rural customers are paying 24% of the notional payment. The use of a credit mechanism, as has been historically used in Hydro's COS, tends to obscure the gross (notional) amount of the financial credit to NP for its generation. Alternatively, a separate COS schedule showing the notional payment from Hydro to NP for the approved value of NP's thermal generation would provide clarity and avoid any misinterpretation. During Hydro's last GRA, the IC and Rural share

[7] Throughout this report, cost impacts for NP refer to allocations prior to Rural deficit re-allocation. The Rural deficit allocation is also affected by the existing credit mechanism and Exhibit 1 shows a cost increase for Rural Labrador Interconnected customers of $87,000.

[8] These values were determined through COS analysis.

of the credit was only referenced with respect to NP's operating costs for its thermal generation[9], without relating the IC and Rural share to the full notional payment derived from Hydro's costs. A separate COS schedule would also show unit costs, which may be then used for comparative purposes against other supply sources or valuation methods.

Recommendation: Compensation for NP's thermal generation should continue as a COS credit, and the notional payment amount should be clearly identified, thus providing greater transparency to the value of the generation.

4.2.3 The Appropriateness of the Credit Affecting System Load Factor

Under the existing mechanism, the use of a demand credit reduces the system demand, and thereby increases the system load factor. This system load factor is used for cost classification between demand and energy for hydraulic generation and power purchase costs. **Exhibit 2** shows that the generation credit in the COS causes $2.4 M of hydraulic generation and power purchase costs to shift from demand to energy. Because customers have different demand and energy ratios, this results in approximately $175,000 shifting from NP primarily to IC. The demand credit for thermal generation does not impact Hydro's actual system load factor, and therefore should not result in a change to the forecast system load factor.

The impact of removing the credit mechanism's effect on the system load factor is illustrated in **Table 3**.

Table 3: Notional Payment - Excluding System Load Factor Impacts

	Notional Payment	COS Allocation	Percent of Total	Net Cost Impact	Change from Existing Mechanism
Newfoundland Power	3,630,019	2,949,152	81.2% (1)	(680,867)	175,033
Island Industrial		443,489	12.2%	443,489	(189,940)
Rural Island Interconncted		237,378	6.5%	237,378	14,907
		3,630,019	100.0%	0	0

(1) Customer demand cost allocation percentages without NP reduction for thermal credit.

Recommendation: The existing thermal credit mechanism's impact on system load factor and the resulting changes in cost classification should not form part of the compensation because actual system load factor is not impacted.

9 Stone & Webster Consultants referred to the IC concern about paying a disproportionate share of NP's thermal generation costs as an apparent anomaly.

4.2.4 The Appropriateness of the Credit for Transmission Costs

Under the existing credit mechanism, NP's transmission allocation factor is reduced by the credit. Of the $3.6 million notional payment discussed earlier, $0.87 million is related to transmission (see **Exhibit 2**, Line 7). These costs are solely related to the common transmission grid[10].

Also, NP's demand at the time of Hydro's Island Interconnected system peak would not be reduced by its thermal generation, since, in contrast with NP's hydraulic generation, thermal generation is not forecast to be run during system peak. Thus, from an embedded cost perspective, NP's transmission demand allocation factor should not be lowered for thermal generation.

Stone & Webster Consultants requested that Hydro prepare an analysis showing the avoided transmission[11] cost associated with each avoided generation cost scenario in **Exhibit 6**. Hydro's analysis concluded that since NP's generation plants were small and somewhat distributed, the removal of NP generation would not require any further local transmission upgrades. Hydro's transmission analysis is presented in **Exhibit 7**.

The impact of removing the credit mechanism's effect on both the system load factor and transmission cost allocation is illustrated in **Table 4**.

Table 4: Notional Payment - Excluding System Load Factor and Transmission Cost Impacts

	Notional Payment	COS Allocation	Percent of Total	Net Cost Impact	Change from Existing Mechanism
Newfoundland Power	2,675,395	2,173,583	81.2%	(501,812)	354,088
Island Industrial		326,860	12.2%	326,860	(306,569)
Rural Island Interconnected		174,952	6.5%	174,952	(47,519)
		2,675,395	100.0%	0	0

Recommendation: Hydro should discontinue compensation for transmission because: (1) thermal generation is not forecast to be run during system peak and therefore should not reduce NP's common transmission cost allocation; and (2) Hydro's analysis shows that there is no avoided transmission cost associated with NP thermal generation.

4.2.5 Appropriate Value for NP Thermal Generation

There are a number of methods by which to value NP's thermal generation, which produce a broad range of values. We have considered the following options:

[10] Transmission costs related to generation are functionalized as such and are included in the generation component of the existing credit mechanism.

[11] Stone & Webster also requested analysis of the value of ancillary services. Hydro indicated that it did not have the appropriate resources to value ancillary services associated with NP generation. Ancillary services were judged not to be a determining factor in selecting credit mechanism options and were therefore excluded from this study.

- Hydro's embedded costs
- NP's internal costs
- Avoided cost
- Cost of a proxy combustion turbine
- Purchase of NP's thermal generation assets

A brief discussion of each of these alternatives is provided below.

4.2.5.1 Hydro's Embedded Costs

Under the existing credit mechanism NP receives a credit for its hydraulic as well as its thermal generation based on Hydro's average embedded costs. The value of the credit, based on Hydro's 2004 average embedded costs of generation and transmission, is $3,630,018, or $82.78 kW/yr. The preceding recommendations to eliminate the system load factor and transmission cost implications for NP's thermal generation result in a revised value of $2,675,395, or $61.01 kW/yr. Average embedded generation demand costs include base load hydraulic and thermal costs as well as peaking costs.

Whether it is appropriate for thermal generation to be credited with average embedded costs depends in part as to whether it is viewed from the perspective of the customer or the serving utility. A customer that owns thermal generation may reason that its generation is available, such that when it operates, it will lower demand and therefore should be credited based on average embedded costs.

Basing the credit on Hydro's average embedded demand costs[12] is reflective of what NP would pay to Hydro if NP's thermal generation did not exist and Hydro had built the generation. A payment based on Hydro's average embedded costs is also consistent with the Board's 1977 recommendation to Government that NP's thermal capacity should be deducted from its demand, effectively crediting NP with Hydro's average embedded costs.

However, the serving utility may value thermal peaking generation, which is not generally called on to run, differently than hydraulic which is expected to run. From this viewpoint, it is arguable whether the value of NP's thermal generation should be based on Hydro's embedded peaking costs alone, rather than include Hydro's full embedded generation costs. **Exhibit 5** shows the components of Hydro's unit capacity costs, including peaking.

If the compensation to NP were based on Hydro's peaking generation rather than the average embedded cost that includes hydraulic, the value would be much lower and may provide NP with an incentive to reject Hydro's payment for its thermal generation and to forecast its thermal to be operating during the system peak. NP would receive the value based on the average embedded generation and transmission demand costs, as well as the system load factor impacts, but it would also incur additional fuel costs[13]. It should be noted that if NP were to forecast its thermal generation to be in operation, the credit for its thermal generation would no longer be applicable to NP's billing demand.

4.2.5.2 NP's Internal Cost

Another option involves paying NP based on the actual cost of its thermal units.

---

[12] Average embedded demand costs, modified to exclude the effects of system load factor and transmission.
[13] Refer to Exhibit 2, Scenario 2 of Stone &Webster's report "Review of Rate Design for Newfoundland Power", filed at Hydro's 2003 GRA as Exhibit RDG-2.

One alternative is to base the payment on NP's total annual revenue requirement associated with its thermal generation, which is approximately $3,704,000[14].

Another alternative is to develop a payment for NP's thermal units on its book value but using Hydro's carrying costs. The carrying charge in this computation would need to include operation and maintenance other than fuel[15] in order to be comparable with NP's credit under the existing mechanism.

Both alternatives offer advantages in that they reflect the age, reliability and operating characteristics of the actual units. However, both options have the disadvantage of relying on cost data of another entity. In addition, payment to NP based on NP's net book value has the same disadvantage as a payment based on Hydro's embedded peaking costs; that is, an inadequate payment may provide an incentive for NP to run its thermal during potential system peaks, rather than accept a payment from Hydro, increasing overall costs to the Island Interconnected system.

4.2.5.3 Avoided Cost

Stone & Webster Consultants requested that Hydro prepare a long-term capacity planning analysis that quantifies the value of NP and IC generation assets. This analysis, which is contained in **Exhibit 6** and summarized in **Table 5** below, shows the additional cost Hydro would incur for the 20-year period 2005-2024 if it were to replace existing NP thermal generation.

Table 5: Value of NP Thermal Generation Assets

Cumulative Present Worth 2005 to 2024 (2005$ x 1000)	
Base Case	2,113,846
Base Case, Less NP Thermal (51 MW)	2,146,781
Change from Base Case	32,935
Components of Change from Base Case:	
Capital	33,452
Fuel	(9,317)
O&M	8,800
Total	32,935

In terms of developing an annual avoided cost value to be paid to NP, one measure is the present value of the avoided cost of NP thermal generation, or $32.935 million, times an estimated levelized fixed carrying charge of 9.69 percent[16], or approximately $3.191 million per year.

A payment to NP based on current avoided costs is supportable in that it reflects the current long-term value to Hydro. However, there are several disadvantages, which include:

[14] NP's fully-allocated thermal generation cost, which includes $2,693,000 of direct costs excluding fuel, plus allocated general system and administrative and general costs. Source: NP's preliminary 2004 cost of service study.
[15] Hydro reimburses NP for fuel separately when it calls on NP's units to be run.
[16] The Capital Recovery Factor was used as an estimate of the levelized fixed carrying charge based on an 8.40 percent cost of capital and a 25 year life of a combustion turbine.

1. An avoided cost payment to NP as a *customer*[17], may not be appropriate, because if Hydro had incurred costs to replace NP's thermal facilities, NP would pay Hydro's average embedded costs, including the replacement thermal costs;

2. The fact that a payment to NP based on the value of new plant does not reflect age and reliability factors associated with NP's actual thermal units. (A listing showing the capacity and age of each of NP's thermal units is contained in **Exhibit 8**);

3. Avoided costs can be an unstable benchmark. If, for example, Hydro constructs a new generating facility, the avoided cost of NP's thermal may immediately go to zero as a result of Hydro having excess capacity in the near-term; and

4. It is unclear as to the extent to which the Board wishes to introduce marginal cost principles in an embedded cost regulatory environment.

4.2.5.4 Cost of a Proxy Combustion Turbine

Another option is to base the payment to NP on a proxy combustion turbine. Hydro estimates the levelized annual cost for a new simple-cycle combustion turbine for peaking capacity, coming on-line in 2007 to be in the order of $109/kW/year.

Basing a payment to NP on a proxy combustion turbine offers the advantage of using a measure that is widely referred to in the electric utility industry, but is not unstable as is the use of avoided costs. However, a number of the disadvantages of a proxy combustion turbine are the same as for avoided costs. They include:

1. A proxy unit may be considered as a surrogate for avoided costs. However, as in the case of avoided costs, Stone & Webster Consultants does not recommend making a direct payment to NP based on a proxy unit. That is, the proxy cost would be included in Hydro's resource mix and NP would effectively end up paying Hydro's average embedded costs of generation, which includes the cost of the proxy unit;

2. A proxy unit is not reflective of the age and reliability of NP's actual units;

3. The proxy cost is sufficiently high as to exacerbate the IC concerns of overpaying for NP's units; and

4. Uncertainty as to the Board's desire to introduce marginal cost principles in the costing process.

In addition, although proxy combustion turbines are not uncommonly employed in the industry in both embedded and marginal COS studies, Stone & Webster Consultants cautions that in the context in which they are employed, the proxy value is only a component of costs – the total of which is ultimately reconciled to an *accounting* revenue requirement. In this instance, the proxy value is put forth as a specific payment to a separate entity.

[17] The distinction is NP as a customer of Hydro, as opposed to thermal generation provided from a separate entity that is not a customer.

4.2.5.5 Purchase of NP's Thermal Generation Assets

Another alternative is for Hydro to purchase NP's thermal generation. Under this option Hydro would own, operate and maintain the thermal units. One basis for establishing a purchase price would be NP's book value. The actual price would be subject to negotiation between Hydro and NP. Also, the PUB would need to approve the purchase and recovery of any premium paid by Hydro in excess of book value in the form of an acquisition adjustment. All costs of ownership would be transferred to Hydro's books.

In contrast with some of the alternatives discussed above that may require periodic revision, the purchase option eliminates the issue in the future.

Stone & Webster Consultants has included this as an alternative only for purposes of completeness in this report, but has not pursued this as a viable option at this time due to the broader ramifications of asset takeovers between two utilities. Other options that have been discussed are simpler and equally effective.

4.2.5.6 Related Considerations

Stone & Webster Consultants believes that there are additional factors that bear on valuing NP generation under some of the alternatives discussed above.

One such consideration relates to the quality of NP generation, e.g., age, start-up time and reliability. While Stone & Webster Consultants is not recommending that a direct payment be made to NP based on either avoided costs or a proxy combustion turbine, these factors, which may be difficult to quantify, would come into play. A value to assign to these factors may be based on a review of industry reliability statistics for outage rates as a function of age or, alternatively, to assign a nominal value of, for example, 25 percent as a reduction to either avoided cost or the cost of a proxy unit as recognition. **Exhibit 8** shows the capacity and age of each of NP's thermal units.

Another consideration is whether NP should receive a reduction of the credit since it also derives value from its thermal units for its own use such as back-up generation and emergency use. The sharing consideration is more readily recognized under the options of paying NP based on its own operating costs or on a direct payment based on its net book value using Hydro's operating costs; however, it could conceptually pertain to any of the payment alternatives[18]. In developing a factor to reflect sharing of NP's thermal units a 50% / 50% split may be supportable. Alternatively, it could be rationalized that the primary purpose of thermal generation is for peaking, which may more appropriately support a 75% (system support) / 25% (NP own use) split.

Solely for purposes of illustration, if a direct payment were to be made to NP based on the cost of, for example, a proxy unit, and in recognition of the above factors, the $109 per kW annual operating cost may be adjusted as follows:

$$\$109/\text{kW} \times 0.75\ [\text{reliability}] \times 0.75\ [\text{sharing}] = \$61.31/\text{kW}$$

Stone & Webster Consultants is not making a specific recommendation as to the level of factors discussed in this section or the extent to which they should be applied, but has included the preceding discussion and illustration principally to recognize that these factors exist conceptually. We recommend, however, that the level of the payment to NP not be so low as to inadequately compensate NP for the value that its thermal generation brings to Hydro's system.

[18] Stone & Webster Consultants is not recommending which, if any, of the payment alternatives should be discounted for sharing of NP's thermal generation, but is simply putting forth the concept, should the Board wish to recognize it.

Table 6, below, provides a comparison of the IC and Rural contribution under each of the alternatives. Factors relating to age, reliability and sharing are not reflected in this table.

Table 6: Summary - Comparison of NP Thermal Generation Values

	Value of NP Generation					
Payment Alternative	Present Value	Annual Amount (1)	Unit Costs Capacity (2)	Unit Costs Load (3)	Contribution of IC and Rural	
	($ x 1000)	($)	$/kW/yr		(%)	($)
1. Avg Embedded Cost 2004 Test Yr		3,630,019	--	82.78	23.6%	855,900
2. Avg Embedded Cost w/ Recommended Changes (4)		2,675,395	--	61.01	18.8%	501,812
3. Avg Embedded Cost of Hydro Peaking Only		1,377,863	27.07	31.42	18.8%	258,440
4. NP Thermal Operating Cost		3,704,000	72.77	84.47	18.8%	694,743
5. NP Thermal NBV w/ Hydro Operating Cost	13,885	1,484,307	29.16	33.85	18.8%	278,405
6. Avoided Cost	32,935	3,191,402	62.70	72.78	18.8%	598,597
7. Proxy Combustion Turbine		5,548,100	109.00	126.52	18.8%	1,040,633

Notes:
(1) Annual amount for 50,900 kW of NP thermal generation capacity.
(2) Annual amount / NP thermal generation capacity (50,900).
(3) Annual amount / NP thermal generation capacity less reserve (43,850).
(4) Recommended changes include removing compensation for transmission and system load factor implications.

Recommendation: While it can be argued which alternative discussed above is the most suitable basis for compensation to NP for their thermal generation, Stone & Webster Consultants believes that Hydro's average embedded costs with the recommended changes represents the best balance in consideration of the pros and cons of each alternative, as well as fairness to the parties and practical implications. This recommendation is made in conjunction with NP's continued obligation to demonstrate the capability of both its hydraulic and thermal generation.

We view a direct payment to NP based on the avoided cost and proxy combustion turbine alternatives as representing upper limits for payment to NP for their older combustion turbines. There is also the concern that either of these alternatives, possibly even after being reduced for reliability factors, will exacerbate the IC issue of fairness if Hydro's payment to NP is sufficiently high. In this regard, Stone & Webster Consultants recognize that it is ultimately the IC that bears the majority of the cost of an increase in the payment to NP based on their contribution to Hydro's coincident peak.

There is also significant concern as to whether it is appropriate for NP, as a customer of Hydro, to be paid avoided costs, since if its thermal generation did not exist, Hydro would incur the cost of replacement and NP would pay Hydro for that thermal capacity based on Hydro's average embedded costs.

With regard to a payment to NP based on Hydro's embedded cost of peaking, we believe that while this alternative has a cost causation basis, the relatively low level of this payment does not adequately compensate NP in light of the value of this generation to Hydro. A sufficiently low payment level may also induce NP to dispatch its generation in a less than optimal manner resulting in an overall increase in costs to the Island Interconnected system. Stone & Webster Consultants recommends that NP not be permitted to both forecast its thermal generation and receive compensation for it.

A payment to NP based on its own internal costs has a rationale in that it recognizes NP's specific thermal units; however, this method relies on the need to identify costs of another utility. Also, a payment based on NP's internal costs brings to the forefront the fact that NP is also using its thermal for its own purposes and that it may be appropriate to incorporate a factor to recognize sharing between both utilities.

In making its recommendation for a basis for compensation to NP, Stone & Webster Consultants recognizes that not all of the criteria we have defined can be met simultaneously and that trade-offs are required. Hydro's average embedded costs with the recommended changes is reconcilable with the use of avoided costs in a regulatory environment[19], preserves the Board's 1977 recommendation to Government and, we believe, provides a fair balance among the identified standards and the interests of all of the parties.

With regard to implementing our preferred alternative, namely, Hydro's average embedded costs with the recommended changes (Option 2 in Table 6), we do not propose that there be a separate payment to NP. Rather, Hydro can continue using the existing credit mechanism for generation, except that for purposes of classifying costs between demand and energy, the system load factor would be determined prior to crediting NP's thermal capacity net of reserves. In developing the allocation factor for transmission, NP would not receive a capacity credit for thermal generation. As mentioned earlier the equivalency of this procedure with a separate payment to NP is demonstrated in **Exhibit 4**.

[19] Hydro's average embedded costs with the recommended changes is reconcilable with the use of avoided costs in a regulatory environment in that if Hydro incurred costs to replace NP's thermal generation, NP would pay demand charges to Hydro based on Hydro's average embedded costs revised to include the cost to replace NP's thermal generation. Hydro's average embedded cost is therefore put forth as being representative of its average embedded cost after the inclusion of costs to replace NP's thermal units.

5 Newfoundland Power's Perspective

Stone & Webster Consultants interviewed NP with respect to their views on valuing their generation and how the generation should be accounted for operationally and financially.

NP indicated that it is important to recognize how NP's generation is factored into Hydro's planning. That is, both NP and Hydro generation are treated on an equal basis and operationally NP generation is available to the system to the same extent as Hydro's.

As to the value of its generation, NP believes that it is more important to view the value from a future, or avoided cost basis, rather than from an embedded cost basis. However, it recognizes that comparing future, or avoided costs to figures derived from embedded costs can result in some confusion. This is especially so considering the current practice within Newfoundland and Labrador to set rates which focuses primarily on the fair allocation of costs based on embedded cost principles.

If the credit for NP thermal generation were eliminated, and NP no longer received an appropriate recognition for its thermal generation, NP believes it would be unreasonable to expect it not to operate its generation for the benefit of its customers even in light of the fact that doing so may increase the overall cost of the Island Interconnected System.

Over the last few years NP has incurred significant cost to upgrade its thermal generation in terms of maintainability in order to increase reliability. This has increased the embedded cost of its thermal generation. NP has justified this cost on the value it provides to customers overall for its support in meeting peaking requirements, and customers locally for the generation's ability to backup local transmission and distribution facilities. Also NP believes its generation is maintained in a manner such that its reliability and availability is similar to that of Hydro's peaking generation units and operationally would have a similar value to the system as Hydro's peaking generation. Further, NP believes that the embedded cost of its generation does not impact on the value that its generation provides to customers, locally and overall. NP sees a continuing role for their thermal generation.

With regard to the operation of the existing mechanism, NP believes much of the debate surrounding the effect of the NP generation credit on the allocation of embedded cost, is attributed to how demand forecasts impact the load factor used to classify Hydro's hydraulic generation costs. If it weren't for this load factor effect, the generation credit would be much more understandable.

Commenting on its hydraulic forecast, NP indicated that forecast hydraulic production at time of peak is based on engineering judgment and recent operating experience. They believe that their forecast is a target for what is likely to be produced during the system peak. However the actual amount will vary depending on plant availability due to forced outages and potential lack of available water.

In assessing the value of generation costs, NP has enunciated the following general principles:

- The value should consider the availability of its generation, both operationally and for planning for the entire system;
- That assessment of the current credit mechanism should recognize that the current method focuses on the allocation of Hydro's costs and that none of NP's thermal generation costs are included in Hydro's cost of service;

- The financial impact on NP of unplanned generation outages should be similar to the impact of unplanned generation outages on Hydro;

- The treatment of the generation credit in rate design, should in principle be reflective of the same considerations that are being given in cost allocation; and

- Any rate design should not create an incentive for NP to run its thermal generation when a lower cost source of production is available within the overall Island Interconnected system.

It is NP's view that a major consideration for this review is that the current practice for determining the costs attributed to all of Hydro's customers is to attribute Hydro's costs fairly in accordance with embedded cost principles. NP believes the existing credit mechanism is a reasonable means to achieve fairness in cost allocation in accordance with embedded cost principles.

6 Newfoundland and Labrador Hydro's Perspective

Stone & Webster Consultants held discussions with Hydro personnel during the course of its review of the operational and financial aspects concerning Hydro's treatment of NP's generation.

From an operational perspective, Hydro has received NP's full cooperation and best efforts each time Hydro has requested generation support from NP. However, Hydro's experience has shown that NP does not have all its resources available throughout the winter period due to scheduled maintenance. This is particularly true during December when NP's generation is undergoing capital improvements. Hydro believes NP should have all its generation capacity available by December 1 for the winter, in order to be consistent with Hydro's longstanding practice of having all its own significant planned generation maintenance completed by that time. Hydro recognizes forced or unscheduled outages can occur during this period and that allowances are necessary for these. However, for those under the control of NP, which are the scheduled outages, these should be confined to short duration when system conditions allow it. This will also be in line with the period of the year in which the Generation Credit is applied to NP's demand billing. Hydro has discussed this with NP and NP has indicated that it will work towards this schedule. To reflect this commitment by NP, Hydro recommends that the Generation Credit test be completed early in December to identify any issues before the generation is required for peak loads.

Hydro also believes that there should be an obligation on the part of NP to have its generation in a state of readiness throughout the winter irrespective of the Generation Credit test results, so that if the generation is required to meet system requirements, it can be depended on to perform to the level of the Generation Credit. As mentioned above this requirement is subject to forced outages that are beyond the reasonable control of NP. However, in such cases Hydro feels NP should be subject to some incentive to correct and restore any problems promptly. Hydro sees this as consistent with the IC's requirement to have its generation available at the forecast level whenever the IC's load requires it. If the IC can't meet this requirement they are subject to higher energy costs. Hydro also believes that there should be higher costs to NP if it cannot perform at the level of the Generation Credit when necessary for system requirements.

From a financial perspective, Hydro agrees that clarification is warranted to clearly set forth the value of the credit to NP and thus welcomes the review by Stone and Webster Consultants and the anticipated ruling by the Board on this issue.

7 Rate Design Considerations

As of January 1, 2005, Hydro began billing NP under the first phase of a demand and energy rate structure. Hydro's COS on which NP's rates are based incorporates the existing credit mechanism described earlier in this report. Billing determinants for pricing are calculated by applying NP's hydraulic and thermal generation capacity net of reserves to its measured native load. This effectively makes the rate independent of the generation at the time of Hydro's system peak.

The alternative Stone & Webster Consultants is recommending retains the credit mechanism, and will not result in any changes to the existing demand and energy rate structure.

The alternatives for a separate payment to NP would result in a purchased power cost to be allocated to all customers. While this represents a procedural change on the costing side, no changes are anticipated on the billing side.

Under the option that discusses the purchase of NP's thermal units, the credit for NP's thermal units should be removed from both costing and billing. However, Stone & Webster Consultants has not recommended that this option be pursued.

8 Summary of Findings and Recommendations

In preparing this report, Stone & Webster Consultants has tried to identify the relevant issues and to address the viewpoints of all of the parties that have commented on the existing credit mechanism, as well as to solicit the comments of NP with regard to what it believes are appropriate approaches. In making our recommendations, Stone & Webster Consultants has tried to assess each alternative in terms of the standards it has defined, which include: fairness, transparency, cost causation, conservation, efficiency incentives and practical implications.

Based on its review, Stone & Webster Consultants offers the following findings and recommendations:

- Stone & Webster Consultants recommends that NP's costing and billing continue to reflect a set credit for its hydraulic generation, in conjunction with NP's continued obligation to demonstrate the capability of both its hydraulic and thermal generation.

- IC have more rigid conditions than NP regarding generation availability during peak periods. If conditions were placed on NP to ensure availability of NP generation, if called upon, during peak periods, then both customer classes would be served under more comparable conditions.

- The existing mechanism should continue to credit NP for its hydraulic generation based on capacity net of reserve rather than on forecast generation, but the relationship between the two should continue to be monitored.

- The feature of the existing mechanism that credits NP's hydraulic generation with Hydro's average embedded cost is appropriate and consistent with cost causation principles.

- Stone & Webster Consultants concludes that NP thermal generation has value to Hydro's Island Interconnected system and contributes to the benefit of all customers.

- Compensation for NP's thermal generation should continue as a COS credit, and the notional payment amount should be clearly identified, thus providing greater transparency to the value of the generation.

- The existing thermal credit mechanism's impact on system load factor and the resulting change in cost classification should not form part of the compensation since the attendant change in load factor is not related to cost causation.

- Hydro should discontinue compensation for transmission because: (1) thermal generation is not forecast to be run during system peak and therefore should not reduce NP's common transmission cost allocation; and (2) Hydro's analysis shows that there is no avoided transmission cost associated with NP thermal generation.

- Stone & Webster Consultants preferred option is to compensate NP for its thermal generation based on Hydro's average embedded cost with recommended changes, in conjunction with NP's continued obligation to demonstrate the capability of its combined hydraulic and thermal generation. In making this recommendation, we recognize that not all of the criteria we have defined can be met simultaneously and that trade-offs are required. We believe this recommended option provides a reasonable balance of the identified standards and the interests of the parties. This option, which recognizes the practical implications of the various alternatives, should allow NP to continue to operate in an efficient fashion.

- Stone & Webster Consultants recommends that should this Board consider other options such as a direct payment to NP based on Hydro's avoided costs or the use of a proxy unit to be more appropriate, that it should also factor in related considerations, such as age and reliability of NP's units as well as shared use between NP and Hydro.

- Stone & Webster Consultants recommends that should NP elect to obtain the benefit from its thermal generation by forecasting its use, that NP should not be permitted to both forecast its thermal generation and receive compensation for it.

- Stone & Webster Consultants supports the existing arrangement whereby Hydro pays NP for fuel when Hydro requests NP to run its thermal generation.

- The existing demand and energy rate structure to serve NP should continue without modification.

9 Exhibits

The exhibits presented in the following pages reflect the analyses performed to develop the findings and recommendations in this report.

Exhibit 1: Customer Impacts – COS Analysis with NP Generation Credit Removed

Newfoundland and Labrador Hydro
2004 Test Year Scenario Analysis

		1	2	3	4	5	6
		Revenue Requirement Before Revenue Credit and Deficit Allocation			Revenue Requirement After Revenue Credit and Deficit Allocation		
		NP Gen Credit Removed	2004 Test Yr PU 14	Increase (Decrease)	NP Gen Credit Removed	2004 Test Yr PU 14	Increase (Decrease)
	Total System						
1	Newfoundland Power	216,463,435	215,607,535	(855,900)	250,530,151	249,809,764	(720,387)
2	Island Industrial	48,695,674	49,329,103	633,429	48,695,674	49,329,103	633,429
3	Labrador Industrial	2,619,369	2,619,369	-	2,619,369	2,619,369	-
4	CFB - Goose Bay Secondary	128,914	128,914	-	2,633,006	2,633,006	-
5	Rural Labrador Interconnected	10,604,823	10,604,823	-	12,677,084	12,764,042	86,958
	Rural Deficit Areas						
6	Island Interconnected	50,752,411	50,974,882	222,471	33,890,311	33,890,311	-
7	Island Isolated	8,013,042	8,013,042	-	1,404,229	1,404,229	-
8	Labrador Isolated	19,777,645	19,777,645	-	5,789,028	5,789,028	-
9	L'Anse au Loup	2,633,257	2,633,257	-	1,449,718	1,449,718	-
10	**Subtotal**	**81,176,355**	**81,398,826**	**222,471**	**42,533,286**	**42,533,286**	**-**
11	**Total**	**359,688,570**	**359,688,570**	**(0)**	**359,688,570**	**359,688,570**	**(0)**
	NP Coincident Peak:						
12	NLH Load Forecast	1,080,700	1,080,700	-			
13	Plus NP Hydraulic Generation		81,600	81,600			
14	Less Credits:						
15	Hydraulic Generation		(81,550)	(81,550)			
16	Gas Turbine & Diesel		(43,900)	(43,900)			
17	Net CP for COS	**1,080,700**	**1,036,850**	**(43,850)**			

Exhibit 2: COS NP Generation Credit Unit Costs

		Total ($)	Total ($/kW/yr.)	Source
A. SUMMARY				
1.	System Load Factor Impacts:			
2.	Demand Costs	(2,410,835)	(54.98)	Ln 18; Ln 18 / 43,850
3.	Energy Costs	2,410,835	54.98	
4.	Total System Load Factor Impacts	0	-	
5.	Existing Demand Unit Costing:			
6.	Generation	2,758,393		Ln 26 x 43,850 x 1.03
7.	Transmission	871,626		Ln 22 x 43,850
8.	Total Demand Unit Costing	3,630,019	82.78	(Ln 6 + Ln 7) / 43,850
9.	Proposed Cost of Service Impact	2,675,395	61.01	Ln 33 x 43,850; Ln 33
B. SYSTEM LOAD FACTOR IMPACTS:				
10.	Costs Affected by System Load Factor ($):			
11.	Hydraulic Generation Costs		96,999,362	TY Functional Summary (1)
12.	Power Purchases		29,510,763	TY Functional Summary (1)
13.	Total		126,510,125	
14.	Change in System Load Factor (%):			
15.	Test Year PU 14 (w/ Generation Credit)		57.81%	COS Sch 4.2
16.	Forecast Load (Generation Credit Removed)		55.90%	
17.	Increase in Energy Classification		1.91%	
18.	Increase in Generation Energy Costs w/ NP Gen Credit		2,410,835	Ln 13 x Ln 17
C. EXISTING DEMAND UNIT COSTING				
19.	Transmission Demand Unit Costs:			
20.	Transmission Demand Costs		25,569,337	COS Sch 2.1A, Col 5
21.	Transmission CP - Test Year Load (kW):		1,286,350	COS Sch 3.1A, Col 5
22.	Transmission Unit Cost - Forecast Load ($/kW/yr.)		19.88	Ln 20 / Ln 21
23.	Generation Demand Unit Costs:			
24.	Generation Demand Costs		80,918,096	COS Sch 2.1A, Col 3
25.	Transmission CP - Test Year Load (kW):		1,324,940	Ln 21 x 1.03
26.	Generation Unit Cost - Forecast Load ($/kW/yr.)		61.07	Ln 24 / Ln 25
D. PROPOSED DEMAND UNIT COSTING				
27.	Generation Demand Unit Costs:			
28.	Generation Demand Costs		80,918,096	COS Sch 2.1A, Col 3
29.	Transmission CP without credit (kW):		1,330,200	Ln 21 plus Gen Credit of 43,850
30.	Plus 3% losses		1,370,106	Ln 29 x 1.03
31.	Less Generation Credit		(43,850)	
32.	Generation CP		1,326,256	
33.	Generation Unit Cost - Proposed ($/kW/yr.)		61.01	Ln 28 / Ln 32

(1) The Test Year Functional Summary filed in response to IC-13 (Rev.) NLH at Hydro's 2003 GRA was based on Hydro's original submission. These numbers have been updated to reflect the 2004 Final Test Year Cost of Service.

Exhibit 3: Customer Impacts - NP Generation Credit

(1)	(2)	(3)	(4)	(5)	(6)
	Total	NP	IC	Rural	Source
A. Customer Impacts - System Load Factor					
1. Cost Allocation Ratios (Test Yr):					
2. Demand	100.00%	80.60%	12.63%	6.76%	COS Sch 3.1A, Col 3
3. Energy	100.00%	73.34%	20.51%	6.14%	COS Sch 3.1A, Col 4
4. Dem-Enr Difference	0.00%	-7.26%	7.88%	-0.62%	
5. Increase in Generation Energy Costs w/ NP Gen Credit	2,410,835				Exhibit 2: Ln 19
6. Cost Difference x Dem-Enr Ratio Differences:	(0)	(175,033)	189,940	(14,907)	Ln 5 x Ln 4
B. Customer Impacts - Existing Demand Unit Costing					
7. Forecast Load (kW)	1,330,200	1,080,700	162,514	86,986	
8. Ratio	100%	81.24%	12.22%	6.54%	Ratio: Ln 7
9. Generation	2,758,393	2,241,013	337,000	180,380	Col 2 - Exhibit 2, Ln 6 Cols 3-5: Col 2 x Ln8
10. Transmission	871,626	708,139	106,489	56,998	Col 2 - Exhibit 2, Ln 7 Cols 3-5: Col 2 x Ln8
11. Total: Generation and Transmission	3,630,019	2,949,152	443,489	237,378	
12. Total Existing Customer Impacts	3,630,019	2,774,119	633,429	222,471	Ln 6 + Ln 11
C. Proposed Customer Impacts					
13. Forecast Load (kW)	1,330,200	1,080,700	162,514	86,986	
14. Ratio	100%	81.24%	12.22%	6.54%	Ratio: Ln 13
15. Generation	2,675,395	2,173,583	326,860	174,952	Col 2 - Exhibit 2, Ln 10 Cols 3-5: Col 2 x Ln14

Exhibit 4: Equivalency of a Separate Payment to NP with the Existing Credit Mechanism

		Total	NP	IC	Rural	Comments
	Allocation Under Existing Credit Mechanism					
1	Demand (MW)	1,330,200	1,080,700	162,514	86,986	Hydro forecast load
2	Less NP Generation	(43,850)	(43,850)			NP thermal capacity net of reserve
3	Transmission Demand Net of NP Generation	1,286,350	1,036,850	162,514	86,986	
4	Generation Demand, incl. 3% Transmission Losses	1,324,941	1,067,956	167,389	89,596	
	Allocation Ratios					
5	Total (Gross) Load (%)	100.00%	81.24%	12.22%	6.54%	Ratio: Line 1
6	Net Load (%)	100.00%	80.60%	12.63%	6.76%	Ratio: Line 3
7	Allocated Generation Demand Costs	$ 80,918,096	$ 65,223,250	$ 10,222,975	$ 5,471,871	Hydro Gen x Line 6
8	Unit Cost ($/kW)	$ 61.07	$ 61.07	$ 61.07	$ 61.07	Line 7 / Line 4
9	Allocated Transmission Demand Costs	$ 25,569,337	$ 20,609,917	$ 3,230,361	$ 1,729,058	Hydro Transm x Line 6
10	Unit Cost ($/kW)	$ 19.88	$ 19.88	$ 19.88	$ 19.88	Line 9 / Line 3
	Allocation Under Separate Payment					
11	Hydro's embedded demand costs	106,487,433	86,514,035	13,009,847	6,963,551	Line 7 total + Line 9 total
12	Plus Payment to NP	3,630,019	2,949,152	443,489	237,378	Exhibit 2, Line 9
13	Allocated on gross Factor	110,117,452	89,463,186	13,453,336	7,200,930	Line 10 total x Line 4
	Comparison					
	Separate Payment					
14	Payment to NP	(3,630,019)	(3,630,019)			-Line 12
15	Allocated Costs	110,117,452	89,463,186	13,453,336	7,200,930	+Line 13
16	Net	106,487,433	85,833,167	13,453,336	7,200,930	Line 14 + Line 15
	Existing Credit Mechanism					
17	Allocated Costs	106,487,433	85,833,167	13,453,336	7,200,930	Line 7 + Line 9
18	Over/<Under>	-	-	-	-	Line 16 - Line 17
19	Net Cost of Service Effect Under Separate Payment	-	(680,867)	443,489	237,378	Line 12 + Line 14

Exhibit 5: Capacity Unit Costs

NEWFOUNDLAND AND LABRADOR HYDRO
Capacity Unit Costs
2004 Final Test Year Cost of Service (PU 14) with System Load Factor based on Load Forecast

		Total	Demand		Capacity Basis	
		Cost	Share	Cost	kW	Demand $/kW/yr.
1.	GENERATION:					
2.	Base Load:					
3.	Hydraulic	96,999,362	44.10%	42,774,241	927,300	46.13
4.	Holyrood, Excl. Fuel	37,245,152	57.72%	21,497,901	465,500	46.18
5.		134,244,514		64,272,143	1,392,800	46.15
6.	Peaking:					
7.	Gas Turbines	2,232,187	100.00%	2,232,187	118,000	18.92
8.	Diesel	1,359,558	100.00%	1,359,558	14,700	92.49
9.		3,591,745		3,591,745	132,700	27.07
10.	Subtotal	137,836,259		67,863,888	1,525,500	44.49
11.	Other:					
12.	Purchased Power	29,510,763	44.10%	13,013,493	66,300	196.28
13.	Feasibility Studies	40,715	100.00%	40,715		
14.	Generation, Excl. Holyrood Fuel	167,387,737		80,918,096	1,591,800	50.83
15.	TRANSMISSION:	25,569,337	100.00%	25,569,337	1,591,800	16.06

Exhibit 6: Value of NP and IC Generation Assets – Generation Analysis

Long Term Capacity Planning Analysis

			Scenario									
			Base Case		Less ALL NP Gen. (146 MW**)		Less NP Thermal (51 MW**)		Less NP Hydro (95 MW**)		Less ALL IC Gen. (181 MW**)	
	Load Forecast		Capacity Added	Installed Capacity	Capacity Added	Installed Capacity	Capacity Added	Installed Capacity	Capacity Added	Installed Capacity	Capacity Added	Installed Capacity
Year	MW	GWh	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2005	1,612	8,573		1,919		1,919		1,919		1,919		1,919
2006	1,621	8,602		1,919		1,919		1,919		1,919		1,919
2007	1,637	8,744	25MW Wind	1,944	25MW Wind	1,944	25MW Wind	1,944	25MW Wind	1,944	25MW Wind	1,944
2008	1,651	8,787		1,944		1,944		1,944		1,944		1,944
2009	1,660	8,864	25MW Wind	1,969	50MW Wind, 48 MW Hydro, 166MW CCCT	2,208	50MW Wind, 48 MW Hydro	2,042	50MW Wind, 48 MW Hydro	2,042	50MW Wind, 48 MW Hydro, 170MW CCCT	2,212
2010	1,676	8,956	25MW Wind	1,994	-146MW NP	2,062	-51MW NP	1,991	-95MW NP	1,947	-181MW IC	2,031
2011	1,693	8,995	48MW Hydro	2,042		2,062	125MW CCCT	2,116	166MW CCCT	2,113	18MW Hydro	2,049
2012	1,751	9,315	18MW Hydro	2,060		2,062		2,116		2,113	112MW CCCT	2,161
2013	1,761	9,400		2,060		2,062		2,116		2,113		2,161
2014	1,769	9,498	125MW CCCT	2,185	18MW Hydro	2,080		2,116		2,113		2,161
2015	1,774	9,513		2,185		2,080		2,116		2,113		2,161
2016	1,786	9,578		2,185		2,080		2,116		2,113		2,161
2017	1,798	9,644		2,185	50 MW CT	2,130	18MW Hydro	2,134		2,113		2,161
2018	1,811	9,714		2,185		2,130	50 MW CT	2,184		2,113		2,161
2019	1,824	9,781		2,185		2,130		2,184	18MW Hydro	2,131		2,161
2020	1,836	9,838		2,185	50 MW CT	2,180		2,184		2,131		2,161
2021	1,847	9,888		2,185		2,180		2,184		2,131	35 MW CT	2,196
2022	1,860	9,950		2,185		2,180	15 MW CT	2,199	39 MW CT	2,170		2,196
2023	1,872	10,017		2,185		2,180		2,199		2,170		2,196
2024	1,884	10,082	50 MW CT	2,235		2,180		2,199		2,170		2,196

	Base Case	Less ALL NP Gen.	Less NP Thermal	Less NP Hydro	Less ALL IC Gen.
CPW to 2024 (2005$ x 1,000):	$2,113,846	$2,389,578	$2,146,781	$2,343,525	$2,921,984
Change from Base Case:	n/a	$275,732	$32,935	$229,679	$808,138
CPW End Effects:	$1,125,926	$1,277,535	$1,128,325	$1,264,074	$1,657,722
Change from Base Case:	n/a	$151,609	$2,399	$138,148	$531,796
CPW TOTAL STUDY PERIOD:	$3,239,772	$3,667,113	$3,275,106	$3,607,599	$4,579,706
Change from Base Case:	n/a	$427,341	$35,334	$367,827	$1,339,934

Notes:
** In all cases, noted generation assets are removed from the system starting in January 2010.
- All cases have been equalized to the capability of the base case scenario.
  That is, by the end of the simulation period, the firm energy capability and LOLH are equivalent to base case values .
- All expansion plans have been optimized to provide the lowest CPW cost with the resources available.

Exhibit 7: Value of NP and IC Generation Assets - Transmission Analysis

Page 1 of 3

The Transmission System on the Island of Newfoundland is planned to withstand the single contingency loss of any element and it is often this requirement for contingency operation that dictates transmission expansion. The east coast transmission system is a two circuit 230 kV network between Bay d'Espoir and the St. John's area and the transfer capability of this transmission system is dependant upon generation dispatch given significant generation in the East and West portions of the system. The limiting contingency on this transmission system does not occur at time of peak but rather at approximately 50% of peak when the Holyrood Thermal Plant on the East Coast is shut down and one of the transmission circuits between Bay d'Espoir and the Sunnyside Terminal Station is forced out of service or taken out for maintenance. On a go forward basis the requirement for transmission line additions on the east coast system will be more a result of where new generation sources are located as opposed to the actual load to be served. Generation additions located off the Avalon Peninsula will likely generate a requirement for transmission upgrade or additions while the status quo will be adequate if the new generation is on the Avalon Peninsula.

In 2002, Hydro completed a comprehensive review of the East Coast Transmission System that investigated the limitations of the existing system, identified excess transfer capability and identified potential short and long term expansion options. The assumptions used in completing the 2002 analysis are still valid and the findings will be used to assist in determining the transmission options associated with the various generation expansion alternatives being proposed in this analysis. A summary of the findings of the 2002 study is as follows.

- Excess or (spare) capacity in the East Coast transmission system is dependant upon the operation of the Holyrood Thermal Plant. For the existing system the spare capacities are as follows:
    - 3 units operating 160 MW
    - 2 units operating 43 MW
    - 1 unit operating 33 MW
    - 0 units operating 25 MW
- With the addition of approximately 80 MVAR of static capacitors at Western Avalon, the thermal up rating of TL 202&206 and the re-conductoring and thermal uprating of TL 203 the transfer capabilities can be increased accordingly:
    - 3 units operating 250 MW
    - 2 units operating 200 MW

- o 1 unit operating 180 MW
- o 0 unit operating 115 MW

- There is still a period of time where it is possible to operate with no generation at Holyrood. As load grows this opportunity will decrease. However, as new generation sources are added the time period may increase if the new sources are located off the Avalon Peninsula and have lower operating cost than Holyrood.

- Once the further generation additions are limited to thermal alternatives, which most likely will be located close to the load centre on the East Coast, there will be year round generation operating on the East Coast and the transfer capability of the transmission lines to the East Coast will be a minimum of the “1 unit “ case (180 MW) which will be adequate until such time that additional generation is added off the Avalon Peninsula.

- Transfer capability beyond the above limits will require a new 230 kV transmission line between Bay d’Espoir and Western Avalon as the existing transmission lines cannot be further upgraded to carry additional capacity

Evaluation of Expansion Alternatives

Base Case

The base generation expansion scenario involves the establishment of 25 MW wind farms in 2007,2009 and 2010 followed by 48 MW of hydro in 2011, 18 MW of hydro in 2012, 125 MW CCCT in 2014 and finally a 50 MW CT in 2024

With this expansion it is likely that all new generation with the exception of the 125 MW CCCT and the 50 MW CT will be located off the Avalon Peninsula for a total of 141 MW of new “off Avalon” generation. Based on the 2002 analysis it will be necessary to add voltage compensation at the Western Avalon Terminal Station and complete the identified transmission upgrades in the 2009/2010 timeframe giving an additional transfer capability of 115 and 180 MW for the 0 unit and 1 unit (Holyrood) cases. There is a possibility that during the 2011-2014 time period a” 0 unit “operation will be desirable. The transfer capability to the East Coast for the 0 unit case is less than the 141 MW of new generation however it is not likely that all of the 141 MW will be available for transfer to the Avalon Peninsula as there will be some load growth on the remainder of the Island. Once the 125 MW CCCT is added in 2014 year round operation at Holyrood will be a reality resulting in a minimum transfer capability of 180 MW.

Page 3 of 3

An order of magnitude estimate of the cost for the transmission upgrades for this Base Case would be $5 million.

Removal of NP and IC Generation.

The expansion plans for the “Less ALL NP Gen.”, “Less NP Thermal” ,”Less NP Hydro” and” Less All IC Gen” are all similar and all involve no more than 141 MW of “off Avalon” generation. The transmission expansion associated with the generation expansion plans will be identical to that of the base case with the additions being required in the 2009/2010 timeframe.

It is not anticipated that the removal of NP generation will require any further local transmission upgrades as the plants are small and somewhat distributed. In the case of the IC generation particularly in Deer Lake local transmission upgrades will be required and further analysis is being completed to determine the magnitude

Exhibit 8: Summary of Newfoundland Power's Thermal Generation Units and Age

NP Thermal Generation Capacity

Plant	Name Plate Rating (MW)	Year Commissioned	Age	Major Refurbishment[1]	Current Capacity (MW)
Greenhill Gas Turbine	25.0	1975	30	Y	22.0
Wesleyville Gas Turbine	14.7	1969	36	Y	14.7
Portable Gas Turbine	7.2	1974	31	Y	7.2
Port Union Diesel	0.5	1962	43	N	0.5
Port aux Basques Diesel	2.5	1969	36	N	2.5
Portable Diesel #3	2.5	2003	2	N	2.5
Contract Diesel[2]	1.5	1999	12	N	1.5

Total					50.9

1 - Major Refurbishment within last 6 years
2 - Used Diesel commissioned by Newfoundland Power in 1999, estimated age is 12 years