Q. Reference: Vol. 2, Tab 8, Demand Management Incentive Account

Table 1 (V2/T8/P2) provides the Reserve Calculation Summary for the years 2005 through 2008.

(a) Please confirm that the intent of the DMI is to provide "a meaningful incentive for Newfoundland Power to undertake reasonable initiatives to minimize peak demand" related to demand reduction factors that are controllable by NP. If this is not the intent of the DMI, please clarify the intent in the view of NP and explain the rationale for including an incentive in relation to variances in wholesale demand that are not controllable by NP.

(b) Please provide details of the potential impact of variances from normal weather on peak demand, wholesale demand charges, the Demand Supply Cost Variance Account (DSCV Account) and the DMI Account (consistent with the magnitude of variances experience in the years 1999 to 2008).

(c) Please provide details of the potential impact of variances from the customer growth forecast on peak demand, wholesale demand charges, the Demand Supply Cost Variance Account (DSCV Account) and the DMI Account (consistent with the magnitude of variances experience in the years 1999 to 2008).

(d) Please provide details of the impact of variances in the forecast impact of DSM programs included in the Conservation Plan on the peak demand and wholesale demand charges, the Demand Supply Cost Variance Account (DSCV Account) and the DMI Account.

(e) For the years included in Table 1 (V2/T8/P2), that is 2005 to 2008, please show the variance in peak demand, the supply cost variance that would have resulted under the DSCV/DMI mechanism and the associated split between Company (Savings) Cost and Customer (Savings) Cost.

(f) For the years 2005 through 2008 please provide a breakdown of the variance in peak demand attributable to variances from (i) normal weather, (ii) forecast customer growth (iii) forecast DSM results, (iv) customer curtailment, (v) curtailment of NP's own load, (vi) system voltage control, and (vii) other factors causing variance from forecast peak demand (specify any other factors and the impact of each).

(g) Please provide for the years 2008 through 2010 the magnitude of the variance in peak demand that would result in a 1% variance in wholesale demand charges under the DSCV/DMI mechanism.

(h) Please confirm that under the DSCV/DMI mechanism NP has an incentive to realize a variance in peak demand that is sufficient to reduce wholesale demand charges by 1% and that there is no incentive for NP to reduce peak demand beyond that level. Does NP consider this incentive to be optimal from the perspective of NP and its customers? Please explain.

A. (a) The DMI Account limits the impact on the Company of purchased power cost variances associated with the demand and energy wholesale rate from Newfoundland and Labrador Hydro ("Hydro"), and provides a meaningful demand management incentive for the Company to undertake reasonable initiatives to minimize peak demand. For more detail on the DMI Account, please refer to *Demand Management Incentive Account* found in *Volume 2: Supporting Materials, Tab 8.*

(b) ***General***

Peak demand is typically driven by a period of extremely cold weather (i.e., a "cold snap") and normally occurs in the early evening (5 pm to 6 pm).[1] Variability in peak demand from year to year can lead to material changes in purchased power demand costs from those reflected in customer rates. Peak demand varies annually depending on when the cold snap occurs and the actual weather conditions during the cold snap.

When a cold snap occurs during the Christmas season, it can result in a relatively high peak demand as a result of the added impact of Christmas load. When the cold snap occurs during March, the level of peak demand will normally be lower because less lighting load is required from customers during the early evenings as the hours of daylight increase.

Hydro and Newfoundland Power have agreed on a weather adjustment mechanism for use in the application of the demand and energy wholesale supply rate. The purpose of this mechanism is to remove the impacts of abnormal peak weather conditions on the Company's billing demand.

Since 2004, Newfoundland Power's forecast of native peak demand (i.e., customers' peak demand requirements) has been determined by applying the 15-year average weather-adjusted load factor to the forecast of produced and purchased energy.[2] The weather-adjusted load factor for each of the 15 years is computed from the weather normalized produced and purchased energy and the weather-adjusted native peak for each year.

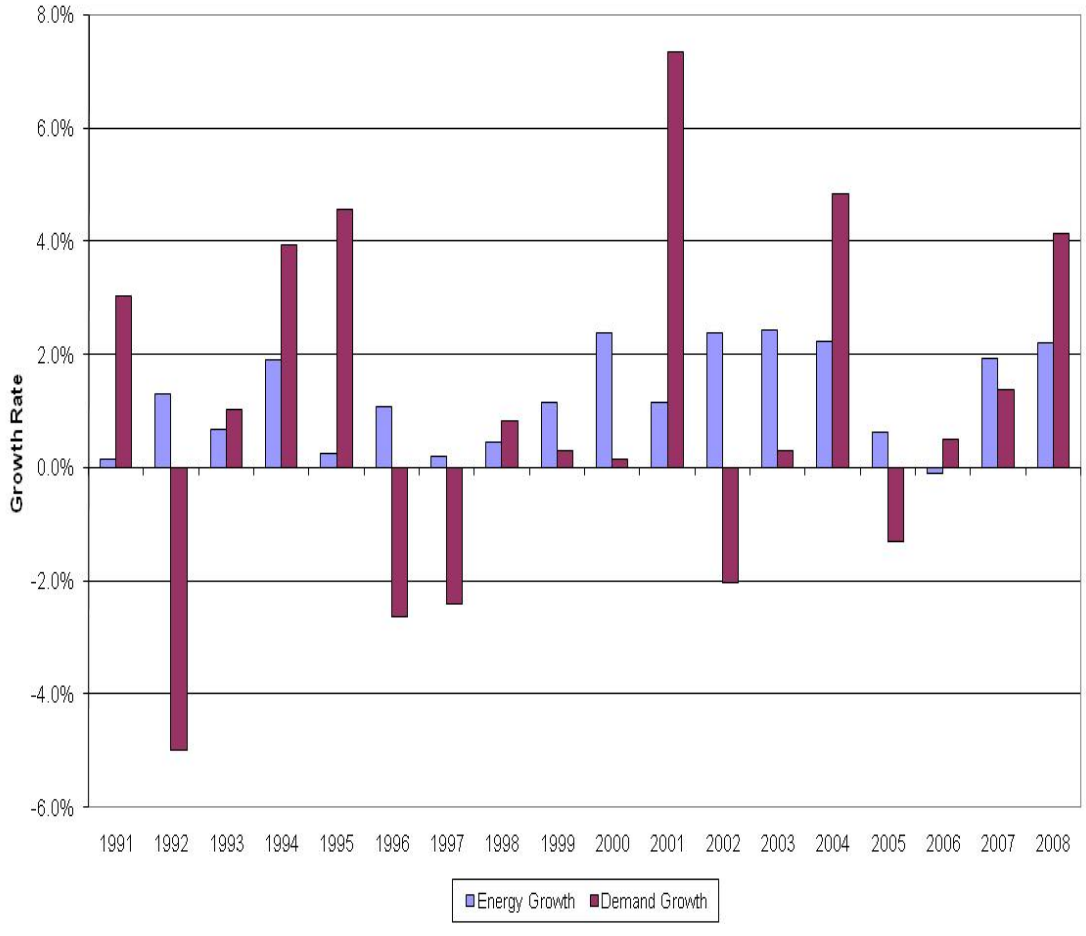
[1] The peak is the maximum amount of customer energy usage required during any 15-minute time period during the year (including Company usage and energy losses).

[2] The forecast native peak demand is then adjusted downward to reflect the impact of load curtailment by Newfoundland Power customers and load management at Company-owned facilities. Newfoundland Power's purchased demand is derived by subtracting the generation credit approved by the Board.

Because the Company's peak demand forecast is based on an historical average load factor, and it changes by only small amounts each year, the change in the forecast native peak generally reflects the addition of new load resulting from customer additions.[3] The load forecast from one year to the next is generally 10 to 20 MW higher than the previous year. However, the weather-adjusted native peak is influenced by numerous factors (as discussed above) and as a result, weather-adjusted billing demand can vary materially from year to year.

Graph 1 provides a comparison of the year-over-year growth rates in weather-adjusted native peak demand with the year-over-year growth rate in weather normalized produced and purchased energy requirements

Graph 1
Growth Rates of Native Peak Demand and Produced and Purchased Energy (year over year)



[3] The load factor used in the Company's native peak forecast for the 2008 test year was 50.02%. The load factor used in the native peak forecast for the 2010 test year is 50.36%.

Based on the historic variability over the period 1991 to 2008, it is reasonable to expect that weather-adjusted native peak demand will vary from forecast within the range of ± 4.0%.

Table 1 shows the pro-forma Demand Supply Cost Variances[4] and the pro-forma transfers to the DMI Account based on a ± 4.0% range of demand variability.[5]

Table 1
Pro forma DMI Account Transfers
Based on a ±4% Variance From Demand Forecast [6]
($000s)

	+4%	**-4%**
Demand Supply Cost Variance[7]	2,424.4	(2,424.4)
DMI Range[8]	549.5	(549.5)
Variance[9]	1,874.9	(1,874.9)
Tax Effects[10]	(600.0)	600.0
Net Transfer To (From) Reserve[11]	**1,274.9**	**(1,274.9)**

Weather Related Forecast Risk

While the weather adjustment mechanism generally provides reasonable estimates of adjustments related to weather, it does not (and cannot) eliminate volatility associated with changes in Newfoundland Power's customers' peak demand.

The 95% statistical confidence of the weather adjustment mechanism is approximately ± 20%. (See Hydro's *Newfoundland Power Demand and Energy Rate Implementation*, July 2004, p.10). With this level of confidence, material

4 The question assumes the existence of a Demand Supply Cost Variance Account; no such account exists. Demand Supply Cost Variances (as referred to in Appendix A, Schedule 4 of the *Demand Management Incentive Account* report found under Tab 8 of Volume 2) are an input in determining transfers to and from the DMI Account.

5 This analysis assumes no variance from the energy supply forecast.

6 The computations are based on a ±4% variance from 2010 test year forecast native peak.

7 A 4% increase in Native Peak in 2008 will result in the Supply Cost increasing by $2,424,365 (50,507.6 kW x 4 $/kW x 12). The effect of a 4% reduction in Native Peak can be limited in some years by the wholesale rate minimum billing demand.

8 The DMI range equals 1% of the wholesale test year demand charges.

9 This is the Demand Supply Cost Variance *less* the DMI range.

10 DMI Account transfers are on an *after-tax* basis. The tax effect is the variance multiplied by the 2010 statutory income tax rate of 32%.

11 Negative transfers indicate amounts credited to customers and positive transfers indicate amounts owed from customers.

demand volatility remains. In the 2004-2005 winter season, peak occurred on December 6, 2004. Weather conditions on that day were unusual. Calculations under the weather adjustment mechanism indicated that peak demand should be increased by approximately 40 MW to reflect normal peak day conditions. Following a review of the matter, Hydro and Newfoundland Power agreed that a peak demand adjustment of 14 MW was a more appropriate reflection of the weather's impact upon the December 6, 2004 peak. This reduction of 26 MW resulted in a purchased power cost savings of $1.45 million.[12]

(c) Customer growth is typically forecast to increase purchased demand from Hydro in a range of 10 to 20 MW per year.[13] The overall potential impact of demand variances from forecast is provided in (b). The Company has not conducted an assessment of potential variances in the manner requested.

(d) The Company's Five Year Conservation Plan (the "Plan") is focused on energy conservation. However, some peak demand reductions are anticipated to accompany the forecast energy savings. The Plan is in its early stages of implementation.

No assessment has been performed on the variability of Plan results as it relates to peak demand.

[12] $1.45 million is determined using the demand charge of $4.65/kW in effect for 2005. (26 MW x 4.65 $/kW x 12 x 1,000).

[13] Source Appendix C. *Customer, Energy and Demand Forecast (Volume 2, Tab 6).*

(e) Table 2 provides the computation of the pro-forma demand supply cost variances assuming the DMI Account had been in effect for 2005 to 2008.

Table 2
Pro-forma Demand Supply Cost Variances
2005-2008

		2005	2006	2007	2008
Peak Demand Variance[14] (MW)	A	1.51	(10.54)	12.72	(27.18)
Test Year Demand Unit Cost ($/kWh)	B	$0.01233	$0.01495	$0.01495	$0.01037
Actual Demand Unit Cost ($/kWh)	C	$0.01209	$0.01449	$0.01441	$0.01014
Variance ($/kWh)	D= C-B	($0.00024)	($0.00046)	($0.00054)	($0.00023)
Purchases[15] (MWh)	E	4,872,666	4,875,768	5,013,056	5,088,014
Demand Supply Cost Variance	F=E x D	($1,169,440)	($2,242,853)	($2,707,050)	($1,170,243)
DMI[16]	G	+/- $588,000	+/- $714,000	+/- $521,000	+/- $528,907
Amount Exceeding DMI	H=F-G	($581,440)	($1,528,853)	($2,186,050)	($641,336)
Company Cost (Savings)	I	($588,000)	($714,000)	($521,000)	($528,907)
Customer Cost (Savings)	J	($581,440)	($1,528,853)	($2,186,050)	($641,336)

(f) The Company has not conducted an assessment of potential variances in the manner requested.

(g) For 2008 and 2009, the ± 1% range for evaluating the Demand Supply Cost Variance to determine the DMI Account transfer was $528,907. This is equivalent to approximately 11.0 MW under the current wholesale rate.

For 2010, the ± 1% range for evaluating the Demand Supply Cost Variance to determine the DMI Account transfer is forecast to be $549,485 This is equivalent to approximately 11.4 MW under the current wholesale rate.

[14] Relative to 2004 test year forecast, for 2005, 2006 and 2007. Relative to 2008 test year for 2008.
[15] Weather Normalized.
[16] Demand Management Incentive.

(h) The DMI Account provides a meaningful incentive for Newfoundland Power to undertake reasonable initiatives to minimize peak demand. Accordingly, Newfoundland Power takes reasonable measures to minimize peak demand requirements of its customers.

Table 3 provides a summary of the reserve calculations for the years 2005 through 2008, with a breakdown of the savings/cost to the Company and customers.

Table 3
Reserve Calculation Summary
($)

	2005	2006	2007	2008
Supply Cost Variance[17]	(438,540)	(2,779,188)	(1,002,611)	(1,170,243)
Company (Savings) Cost	(438,540)	(714,000)	(521,000)	(528,907)
Customer (Savings) Cost	-	(2,065,188)	(481,611)	(641,336)

As Table 3 shows, the operation of the DMI Account and its predecessor, the PPUCVR Account, has resulted in supply cost savings to the benefit of customers and the Company. These savings do not indicate the Company limits its peak demand reduction efforts to minimize the savings being provided to customers. The experience with the demand management incentive thus far indicates a balanced approach to incenting the Company to achieve savings to the benefit of the Company and its customers.

[17] For the years 2005 to 2007, the supply cost variance is relative to forecast unit supply cost. For 2008, the supply cost variance is the variance from test year unit demand supply cost. Transfers to reserves are on an after-tax basis. Benefits credited to customers through amortizations (as approved in Order No. P.U. 32 (2007)) or through the RSA (as approved in Order No. P.U. 6 (2008)) are effectively on a before tax basis.