VIA RESS AND COURIER

January 14, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Hydro One Networks Inc. Changes to Uniform Transmission Rates
Submission of AMPCO Evidence
Board File No. EB-2008-0272

In accordance with Procedural Order No. 2 dated December 1, 2008, attached please find AMPCO's evidence in the above proceeding entitled "The Benefits of Improvements in Transmission Rate Design".

Please contact me if you have any questions or require any further information.

Sincerely yours,

ORIGINAL SIGNED BY

Adam White

Copies to: Glen MacDonald, Hydro One Networks Inc.
Intervenors

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ONTARIO ENERGY BOARD

IN THE MATTER OF the sections 25.30 and 25.31 of the Electricity Act, 1998
AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an electricity transmission revenue requirement change.

EVIDENCE OF THE ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

The Benefits of Improvements in Transmission Rate Design

Contents

1 Introduction

Hydro One Networks Inc. has made an application to the Ontario Energy Board for approval of proposed revenue requirements and rates for 2009 and 2010. Hydro One's proposes to maintain the status quo in terms of rate design: rates that were designed and first approved by the OEB pursuant to an application in 1999 (RP-1999-0044).

AMPCO hopes to demonstrate with this submission that Hydro One's rates are an impediment to efficient demand management. To that end, AMPCO will put forward a superior rate design that:

1. allocates transmission costs more fairly among customers according to how those customers use the transmission system;
2. promotes better asset utilization and more efficient transmission by Hydro One;
3. Provides more efficient signals to customers regarding the costs their consumption imposes on the system;
4. promotes more efficient demand management and specifically peak-shifting; and
5. provides greater revenue certainty to Hydro One and greater cost certainty to customers, reducing risk and increasing the financial viability of the electricity sector overall.

AMPCO believes that this will produce a more efficient outcome than that proposed by Hydro One.

Circumstances have changed since 1999. Ontario's energy policy has changed since 1999. The profile and needs of customers has changed since 1999. The transmission company has changed since 1999. Hydro One, however, feels that its rates remain appropriate.

The government has directed the OPA to achieve 6300 megawatts of conservation and demand management as measured at peak demand. The Government of Ontario's energy policy therefore explicitly favours measures to reduce demand during peak periods. [Energy Minister Duncan's Supply Mix Directive to the OPA]

Ideally, charges for the use of electricity system assets should reflect the cost drivers associated with operations and especially investment in new infrastructure. A rate design that would reflect drivers for cost and investment would align with government policy and at the same time improve asset utilisation, with concomitant reductions in the life cycle cost of energy delivery.

The current Network Charge Determinant is arrived at by calculating a monthly average of total costs allocated to the network assets divided by customers' expected demand during monthly system peaks (or 85 percent of customers' demand not during monthly system peaks but between the hours of 0700 and 1900 on working weekdays).

The current network charge is inconsistent with energy policy in Ontario. As it is currently designed, the 85% "ratchet" mutes the price signal to customers to reduce their use of transmission assets during periods of peak demand. The ratchet effectively makes customers largely indifferent to the effect of their consumption on the transmission system; there is no penalty for consuming during peak periods and no reward for shifting consumption to off-peak periods. As a consequence, peak system demand will grow faster than it otherwise would, increasing needs for investment to meet peak demand, leading to over-spending, poorer asset utilization, inefficient demand management and unfair allocation of costs, all of which are contrary to the statutory objectives of the OEB (as set out in the OEB Act, 1998) and the energy policies of the Government of Ontario.

The current method of charging based on each month of the year further mutes the price signal to customers. The level of investment required for network assets is largely determined by the maximum capacity these assets will be required to serve. For extended periods in the spring and fall, peak demands have little or no influence on the requirement for system capacity. Basing a large portion of transmission charges in periods that do not significantly influence the cost of the assets further reduces the price signals that are needed to incent demand response.

2 The Effect of Price on Industrial Demand for Electricity

AMPCO will set out in its evidence an analysis designed to prove that industrial customers respond to price signals. Industrial customers respond in two ways: (1) structural demand management and (2) dynamic demand management.

Summary statistics of industrial demand by hour of day and day of week show a clear pattern of lower demand during on-peak hours and higher demand during off-peak hours. This "structural demand management" results from decisions of individual industrial customers to maximize electrical consumption during off-peak periods and to minimize electrical consumption during on-peak periods. It is a rational economic response to well understood price patterns in Ontario's market. Industries with discretionary loads or with electrical loads that are intermittent, i.e., not required to run continuously, tend to schedule those loads or operations as far as possible during off-peak hours. In a mining operation, for example, pumping and hoisting operations are routinely scheduled for off-peak periods. In the steel industry, electrical melting operations are generally scheduled as far as possible during off peak periods and maintenance outages are scheduled during peak periods.

An analysis of industrial electricity consumption data provided by the IESO, as shown in the following table, shows average hourly industrial demand by day of week and hour of day during June, July, August and September in 2007 highlighting the 10 hours of the highest consumption and the 10 hours of the lowest consumption. This shows a clear pattern of higher consumption during weekends and weekday off-peak hours and lower consumption during working weekday hours.

Table 1 Average Industrial Consumption: Summer 2007

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
1	2622	2735	**2763**	**2743**	2695	2699	2694
2	2656	**2761**	**2776**	**2758**	2723	2739	2734
3	2683	**2760**	**2772**	**2759**	2733	2740	2722
4	2672	2740	**2761**	**2748**	2708	2739	2720
5	2650	2709	2725	2715	2664	2719	2710
6	2617	2613	2611	2589	2560	2612	2640
7	2580	2526	2484	2436	2402	2496	2596
8	2504	2506	2473	2417	2358	2465	2556
9	2496	2487	2453	2391	2351	2450	2541
10	2498	2471	2435	2378	**2338**	2423	2530
11	2475	2457	2413	2368	**2328**	2404	2513
12	2484	2437	2392	2348	2349	2389	2488
13	2473	2414	2396	**2334**	2344	2402	2480
14	2485	2431	2413	**2337**	2352	2418	2466
15	2486	2420	2397	**2344**	**2338**	2410	2450
16	2476	2408	2395	**2340**	**2337**	2421	2456
17	2461	2409	2373	2352	**2324**	2422	2454
18	2447	2398	2392	2361	**2336**	2415	2440
19	2477	2437	2421	2403	2379	2469	2457
20	2509	2471	2446	2442	2411	2501	2478
21	2541	2509	2495	2485	2457	2539	2502
22	2564	2577	2559	2534	2512	2575	2514
23	2616	2662	2622	2588	2583	2628	2549
24	2684	2726	2684	2643	2642	2669	2591

In a report entitled "Do Firms Shift Demand in Response to High Prices? An Empirical Analysis", commissioned by AMPCO, Dr. Anindya Sen estimates electricity demand elasticity with respect to electricity prices for five industry sectors. These results are shown in the following table.

Table 2 Price Elasticity of Demand by Sector (Summer 2007)

	Pulp	Metal	Iron	Motor	Petrol
Elasticity of Current Demand with Respect to the Current HOEP	-0.226	-0.045	-0.0439	0.367	0.013
Standard Error of Estimate	0.0219	0.013	0.017	0.046	0.009
Confidence of Estimate	99%	99%	99%	99%	
Elasticity of Current Demand with Respect to the Average HOEP for the Previous 12 Hours	0.0969	0.058	0.025	0.151	0.016
Standard Error of Estimate	0.0216	0.011	0.019	0.044	0.009
Confidence of Estimate	99%	99%		99%	95%
Month Fixed Effects Estimated?	Yes	Yes	Yes	Yes	Yes
Observations	244	244	244	244	244
R Square	0.2707	0.4775	0.4305	0.3665	0.9364

For the pulp and paper sector, for example, an elasticity of -0.226 means for every percentage change in the Hourly Ontario Energy Price ("HOEP"), electricity consumption by the pulp and paper sector will decline by 0.226 percent in real-time. The results of the analysis suggest that this outcome would be expected to occur in no fewer than 99 cases out of 100, i.e., that the confidence in the estimate is better than 99 percent.. Again for the pulp and paper sector, for every percentage increase in the average HOEP during the previous 12 hours, electricity consumption would be expected to increase by 0.0969 percent, in no fewer than 99 cases out of 100.

Dr. Sen's analysis finds a statistically significant relationship between real time price HOEP and real time demand, as well as a statistically significant relationship between average prices in on-peak hours and average consumption in off-peak hours. This finding supports the conclusion that industrial customers don't simply reduce consumption in real-time when prices are high, but they also shift consumption from peak periods with high prices to off-peak periods. The results suggest that increasing price signals during on-peak periods will not only cause demand to be reduced during peak periods, but it will also cause demand to be increased during subsequent off-peak periods. Intuitively one can understand that where a customer reduces demand during peak hours, lost production must be made up during off-peak hours.

3 A Shadow Price for Transmission Network Services

The concept of a "shadow price" is employed in economic analysis to reflect the opportunity cost of a product or service or, in other words, to reflect the intrinsic economic value of an outcome. In the case of transmission network services, there is no market to reveal the marginal cost of the service or the marginal willingness of a customer to pay for it. The costs are approved by the Ontario Energy Board and a specific rate is ordered. The current rate does not reflect a determination of the economic value or marginal cost of network services.

In order to model the effect of a transmission rate change on consumption behaviour by customers, we convert a network charge into a shadow price or proxy for the opportunity value to a customer of reducing consumption during system peak periods. The rate design proposed in this submission would have a customer's transmission rate in one year based on that customer's demand during the hour of system peak demand during the five peak demand periods in the previous year.

Calculating a shadow price for transmission network services requires some assumptions about the amount and duration of demand reduction that would be necessary in order to realize a reduction in transmission rates to be paid. Predicting the hour of system peak demand is not simple. Demand varies in response to a number of factors; the primary factor is weather. In order to reduce consumption during an hour of system peak demand, a customer would predict when that hour of peak demand would occur and then, to ensure that the peak hour would not be missed, would reduce consumption some hours before, during and after that time. The experience of Ontario customers with operations in other jurisdictions with similar rate designs suggests that 3 to 5 production curtailments for periods of 2 to 4 hours in duration each would likely be necessary to ensure that consumption is reduced during the actual hours of a system peak.

Assuming that a yearly transmission network services rate is based on a customer's peak during 5 system peaks, regardless of when they would occur, and a further assumption that a customer would be expected to curtail production between 15 and 25 times in a year, for periods of 2 to 4 hours duration each, then a customer would curtail production between 30 and 100 hours in a year in the expectation that these demand reductions would be sufficient to guarantee reduced demand during the five periods of system peak in a year.

An equation for calculating the shadow price is shown below.

$$Shadow\ price\ (\frac{\$}{MWh})\ =\frac{Network\ charge\ (\frac{\$}{MWh})\ X\ Demand\ reduction\ (MW)}{Duration\ of\ reduction\ (Hours)}$$

Based on the current network charge determinant of $2.57/kW-month, for every megawatt of reduced demand by a customer during all five periods of system peak demand, the annual savings in terms of reduced transmission rates paid in the subsequent year would be $30,840. In a worst case scenario, where 5 demand reductions are required each of 4 hours duration to avoid each system peak period, the value of transmission cost savings—the shadow price for transmission network services—would be $308 per MWh. This analysis is summarized in the following table.

Table 3 Calculating a Shadow Price for Transmission Network Charges

Network Charge Determinant	$2.57	per kW-month
Transmission cost savings per MW average demand response	$2,570	per MW-month
Transmission cost savings per MW average demand response	$30,840	per MW-year
Number of peak demand periods avoided to achieve 1 MW savings	5	per year
Number of demand reductions to avoid each peak demand period	5	per period
Number of demand reductions to avoid all peak demand periods	25	per year
Duration of average demand reduction to achieve 1 MW savings	4	hours
Demand reduction-hours to achieve 1 MW savings	100	hours
The value of transmission cost savings per MW of demand response	$308	per MWh

4 The Effect of Transmission Rates on Industrial Peak Demand

Using the estimated shadow price for transmission network services, and based on estimates of price elasticity of demand for each sector, we can estimate the amount of industrial demand response that would occur from a change in transmission network rates.

The following table shows summary statistics for industrial demand and HOEP during the summer months (June, July, August and September) of 2007, as well as the transmission shadow price, the percentage of summer hours during which demand reductions to avoid peak periods will occur (calculated as 100 hours of reduction as a fraction of 2968 summer hours (i.e., 122 days times 24 hours each). The table also shows estimates of the effect of average Ontario demand on average HOEP for 2007 during on-peak hours and during off-peak hours.

Table 4 Summary Statistics and Assumptions

	Industrial demand (MW summer 2007)			**Average HOEP summer 2007**	**Transmission Shadow Price**	**Peak periods as percentage of summer hours**	**Effect of average demand on average HOEP on-peak**	**Effect of average demand on average HOEP off-peak**
	Min	Mean	Max	($/MWh)	($/MWh)	%	$/MWh	$/MWh
Pulp	271	446	575					
Metal	404	521	607					
Iron	298	475	589	$49.50	$308.40	3.4%	$0.012	$0.010
Motor	62	153	212					
Petrol	134	220	260					

While the mean demand values are used to calculate the relative change in demand resulting from a change in demand, the minimum and maximum values are assumed to set lower and upper bounds of the amount of demand response that will occur. It is possible that given a sufficient price signal, firms may take steps to increase the amount of flexibility in their operations so as to realize additional benefits from peak-shifting; we have not estimated the extent to which this might occur. We assume that a change in transmission rates will encourage demand responses within previously observed bounds. The following tables show our estimates of demand changes by sector in response to changes in transmission rates. Our results suggest that demand will fall in real time as prices rise, but will then rise in subsequent off-peak (and anticipated lower price) hours.

5 The effect of Transmission Rates on Energy Prices

The first table shows that the change in rates we propose will cause significant demand reductions during peak periods (i.e., during 100 hours of the summer months), which would cause demand during on-peak hours of those months to be reduced by 19 megawatts. This demand reduction is estimated to cause HOEP to be reduced by $0.23. The reasons for this are intuitive. The overall level of demand in Ontario is a significant determinant of wholesale prices (or HOEP) and especially so during peak periods. If transmission rates are designed to improve signals for peak demand reductions, and those demand reductions occur as the analysis suggests it will, then reduced demand during peak periods will cause wholesale prices to be lower.

Table 5 The Effect of Transmission Rates on Demand in Real-Time

	Elasticity of Demand: Current HOEP	**Change in demand in response to change in price**	**Absolute change in demand during peak periods**	**Demand response as average of summer hours**	**Effect of demand response on HOEP**
		%	MW	MW	$/MWh
Pulp	-0.226	-204%	-175	-6	-$0.07
Metal	-0.045	-47%	-117	-4	-$0.05
Iron	-0.0439	-42%	-177	-6	-$0.07
Motor Petrol	0.367	113%	-91	-3	-$0.04
			-560	-19	-$0.23

Note: statistically insignificant results are excluded

The next table shows the demand response to average prices in the previous 12 hours.

Table 6 The Effect of Transmission Rates on Peak-Shifting

	Elasticity of Demand: Average HOEP for past 12 hours	Change in demand in response to change in price	Absolute change in demand during peak periods	Demand response as average of summer hours	Effect of demand response on HOEP
		%	MW	MW	$/MWh
Pulp	0.0969	87%	129	4	$0.04
Metal Iron	0.058	61%	86	3	$0.03
Motor	0.151	47%	59	2	$0.02
Petrol	0.016	7%	16		$0.00
			290	9	$0.09

Note: statistically insignificant results are excluded

This analysis suggests that where average prices are high, demand during subsequent off-peak and lower price periods will increase. Since Ontario demand is a determinant of price, one would expect these demand increases to cause prices to increase. Because, however, these increases occur during off-peak hours, when Ontario demand is generally lower and electricity supplies are more abundant, the effect of demand increases during these periods is less than it is during peak periods. Our results suggest that the effect of a 1 MW increase in demand during peak hours causes price to increase by $0.012 while that same 1 MW increase in demand during off-peak hours would cause price to increase by $0.010. Even though these differences might appear to be relatively small, the combined effect is clear: <u>changing transmission rates to promote efficient demand management will cause wholesale electricity prices to be lower</u>. Were these results to be weighted by demand (which is much higher on average during peak periods than it is off-peak) the results would be magnified.

Even without analyzing the effects of changing transmission rates on transmission customers, it is clear that changing transmission rates will produce an overall efficiency gain for Ontario.

6 AMPCO's Proposed Rate Design

AMPCO is recommending that a customer's monthly transmission demand charges be determined on the basis of the average of that customer's coincident peak demand on the days of the 5 highest peaks in Ontario demand in the previous year.

Because the transmission rate for a customer in any given year is based on performance in the previous year, and because we assume that transmission rates for 2009 would continue to be based on the current network charge determinant, while transmission rates in 2010 would be based on the proposed 5 peak period model, this means that all customers will see benefits from HOEP reduction in 2009 while industrial customers will only see transmission cost savings in 2010 based on their success in curtailing production during peak demand periods in 2009.

This design does not require designation in advance of the months in which the peak days are expected to occur. AMPCO recognizes that, from year to year, the 5 peak days have occurred in different months.

Because AMPCO's proposal requires that a customer's network charge be determined by its demand at peak during the previous year, implementation cannot happen immediately. Therefore, AMPCO recommends that 2010 network charges be based on 2009 demand, calculated as follows:

$$Network\ Charge\ Determinant\ in\ 2010 = \frac{Network\ Revenue\ Requirement\ in\ 2010}{\sum(Customer\ Demand\ During\ 5\ Peak\ periods)\ \times 12}$$

For implementing rates, the charge determinant could be set according to demand in the 12 months up to Oct 31 of the previous year, or some slightly earlier date if that is necessary to accommodate the time needed to collect data, calculate the new determinant and notify customers.

AMPCO proposes removal of the "ratchet" on the network charge determinant, for these reasons:

1. The existence of the ratchet has no foundation in cost causality, since the primary determinant of network design and cost is peak demand and the ratchet operates outside times of peak demand. While ratchets are used in other jurisdictions (e.g., Alberta), these instances are normally for line and transformation charges where the assets are specific to a customer or sub-group of customers.
2. The ratchet is "anti - CDM" in that its primary design intent appears to have been to provide a specific disincentive to customers that might seek to manage their transmission cost by reducing demand at peak periods.
3. If the ratchet were removed and customers did respond by reducing demand during peak periods, this would in turn reduce price such that the aggregate benefit to all Ontario customers would exceed the wealth transfer from removing the ratchet.
4. By providing an incentive to customers to reduce their demand at peak times, the overall utilisation of the transmission grid, as well as supply resources will be improved. It is especially important that this incentive be in place for LDCs, since most of the demand growth in Ontario that is driving the expansion of the transmission asset base is occurring with these loads.

7 Implications for Transmission Revenue Certainty

Currently, Transmitters receive their revenue monthly, based on customer demand in the previous month. Since monthly customer demand fluctuates due to economic, weather and other factors, this approach to recovering the transmission revenue requirement inherently introduces uncertainty in both absolute revenue and cash flow for the transmitter. This introduces an unpredictable mismatch between revenue and outgoing cash flow for operations. The difference between the two must be handled in some way, typically by adjusting working capital requirements each month.

In contrast, AMPCO's recommendation would provide transmitters with a constant and predictable revenue stream for the year. This revenue predictability should make the transmitter a lower borrowing risk, for example by providing revenue assurance even if demand turns out to be lower than expected.

8 Implications for Industrial Customers

Customer strategies to take advantage of the incentive to reduce demand on the network at peak times will necessarily develop and evolve over time. Nonetheless, there is sufficient data to rough out what types of strategies are likely to work, at least in the first year or so.

Customers cannot know in advance when the peak days of the year will occur, nor can they know with precision at what hour system peak demand will occur on any given day. This uncertainty means that, to maximize the potential benefits of demand reduction, customers will need to reduce demand several times for each peak day they successfully locate.

To illustrate how customers can be expected to respond to the recommended charge determinant, a scenario has been constructed for 2007 using historical data.

Using IESO Hourly Ontario demand data for 2003-2008, AMPCO has located the five highest peak days for each year, and the peak demand during the highest and fifth highest days, as shown in the following table:

Table 7 Peak Ontario Demand on Highest and Fifth Highest Peak Day (2003-2008)

Year	2003	2004	2005	2006	2007	2008
Peak on highest peak day	24753	24979	26160	27005	25737	24195
Peak on 5th highest peak day	23891	23976	25816	24857	25003	23309

Three of the six years used in this analysis, experienced peaks on the fifth highest day at less than 24,000 MW. Note also that there is no obvious trend in the peaks on the fifth highest day from year to year.

This level of uncertainty means that an energy manager seeking success at reducing its network charges will need to take a conservative approach at the beginning of the year. A threshold level of 23,000 MW was assumed to be a good starting point, as this is within 2% of the lowest of the fifth peak days.

Initially, a customer would seek out the first five days where the peak exceeds 23,000 MW, on the assumption that at least one of these would have a strong chance of being the fifth peak day or better by the end of the year. In 2007, the first five days with peaks over 23,000 Mw occurred on January 16, January 25 and February 5-7 inclusive.

Once the customer has responded on the first five peak days, the selection criteria for deciding when to shift demand can be narrowed to picking only those days when the peak is expected to exceed the lowest of the peaks that has already been avoided. This becomes a rolling process with increasing thresholds before demand response is activated.

To successfully capture the highest 5 peak days in 2007, this approach would have required the customer to activate demand response on 17 days, ending August 29.

Even when a customer has some confidence about when a peak day may occur, it still cannot estimate with precision at exactly what hour the peak will happen. Typically, demand will be within a percent or two of the actual peak for two or more hours, especially for summer peaks.

This means that, to be assured of success, the customer must typically reduce demand for 3-5 hours on a day when a peak is anticipated.

For the example of 2007 in this scenario, a customer would have had to reduce demand between 51-75 hours to assure success at responding to the five highest peak days in the year.

The scenario above is probably optimistic in terms of anticipating the costs the customer will incur to ensure capture of all 5 peak days. This is largely because it has the benefit of hindsight, working with actual demands. When anticipating a peak day, the customer would have to work with pre-dispatch data from the IESO (both day-ahead and in the pre-dispatch hours leading up to real-time , which introduces uncertainty that can only be countered by making more attempts to “hunt” the peak.

An additional source of uncertainty for the demand responsive customer comes from the actions of other customers seeking to avoid the same peak. As more customers seek to shave the peak, the aggregate effect will be to flatten the peak. While this is aligned with government policy, it also increases the cost and risk of peak-shifting by requiring demand response during a greater number of hours. Theory suggests that over time, the costs and benefits of peak-shifting would be expected to equilibrate.

The example above is based on consultations with an industrial customer with operations in jurisdictions with network rates similar to those which AMPCO is proposing. Customers with different cost structures and process constrains may respond differently, but likely with a broadly similar approach.

LDCs can also use the approach above, where they have some control over their peak demand. The PeakSaver program that has been funded by the OPA and is implemented in many LDCs is one example of such an opportunity and other options such as water heater control could also be used.

9 Implications for Other Transmission Customers

Industrial customers will benefit from having known transmission costs for the coming year, which in turn removes some of the risk that they will price their products incorrectly and either lose market share from over-estimating cost or lose profit from under-estimating cost.

LDCs and their retail customers could also benefit from having predictable transmission costs, since this predictability could allow them to decouple transmission charges from (variable) energy consumption.

At the same time, the opportunity to reduce future (next year) costs for transmission provides a powerful incentive for all customers to manage their use of transmission assets. Industries with process flexibility and LDCs operating such programs as Peak Saver could take advantage of this design to reduce their costs and improve overall utilisation of both the transmission and supply system.

In the mid to longer term, the pursuit of transmission cost reductions by LDCs through use of demand response programs may be more effective in controlling the increase in the transmission rate base than action by large industries. Of the development capital programs proposed by Hydro One in this application, the large majority of the non-IPSP related projects are driven by the need to accommodate increasing demand by the LDCs (Exhibit D1/Tab 3/Sch3/Tables 4&5). Moreover, much of the IPSP and pre-IPSP capital relates at least indirectly to load growth in LDCs, since industrial demand has been declining slightly over the past few years. A rate design that incents rather than discourages demand response specifically to improve transmission utilisation would send the proper price signal to manage use of electricity system assets overall and transmission grid assets in particular.

For LDCs that are experiencing growth in customer demand, this recommendation would introduce a lag in transmission costs that would benefit growing LDCs. Customers that generally have static or shrinking demand would experience a corresponding negative impact.

10 Implications for Transmission Regulation

Currently, recovery of a transmitter's revenue requirement (TRR) is sensitive to the accuracy of the load forecast. This reality has resulted in significant effort by all parties to the process to ensure that transmitters produce reliable load forecasts and employ appropriate techniques for both forecasting and weather correction. The (proper) reluctance of transmitters to expose themselves to risk on the load forecast has resulted in forecasts that tend to err on the low side and hence result in over-earnings. AMPCO and others argued this issue in EB-2006-0501.

If AMPCO's proposal for redesign of the Network Charge Determinant is accepted, the forecast accuracy issue becomes moot with respect to revenue risk for the transmitter and cost risk for the customer. If the concept of setting charge determinants based on the previous year's performance were extended to other pools as well, the load forecast issue becomes one that is restricted largely to the extent to which it supports proposals for capital investment.