Meeting Notes #6
Cost Allocation Working Group

Thursday, April 24, 2003
9:30 a.m. - 3:15 p.m.

1. Use of stratification in sampling

As textbooks (e.g. AEIC Load Research Manual) indicate use of stratified sampling can reduce the number of new sampling meters required, the group discussed some practical issues associated with stratification.

A) The discussion was kicked off by Paula Zarnett. She mentioned there are two general approaches:

- One is to stratify based on consumption.
- The other is to collect end-use information (for example, to distinguish between residential customers who do and do not have electric water heating).

B) The group also heard from an invited guest, Dr. Neil Mather (one of the coauthors of the 1979 Ontario Hydro load research manual). He explained that in the past, appliance surveys were conducted to directly measure end uses. Such studies are costly however, and therefore it was anticipated few utilities would undertake new surveys [Editor's note: Last week group discussed gathering appliance saturation data from other sources, such as Stats Canada.] Stratification by kWh could avid this expense, since energy consumption patterns would be used to infer appliance loads.

In setting up stratums in the residential class, as many as 8 strata could be needed in theory, based on various combinations of air conditioning, electric heating and electric hot water usage. In practice, there may be no samples in come classes, so only 5 residential strata could be needed.

In his presentation, Dr. Mather touched on miscellaneous other topics in load data collection and research:

- He recommended against use of convenience and judgment samples (since not truly random), but acknowledged use of "replacement sample for simple refusal, known problems (electrical, human, location)".
- Some methods for lowering the standard deviation included weather normalization (discussed below) and Bayesian techniques that make formal use of prior knowledge (some group members have expressed interest in exploring such techniques, with the hope that it could lead to a reduction in the number of new meters required to update the old Ontario Hydro load data on the IMO web site).

2. Current Ontario Weather Adjustment Methodologies

Stanley But did a presentation on weather normalization methodologies that are currently in use in the Ontario electricity sector:

- One method was developed by the forecasting unit at the former Ontario Hydro. This method is currently used by Hydro One, OPG and IMO (and some LDCs that use the assistance of Hydro One). Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity.

- A second method uses the Hourly Electric Load Model (HELM) developed by EPRI in the USA. Hydro One has this model and received training for its proper use. The general approach is very similar to the above. The model calculates normalized weather for each day using 31 years of weather data (temperature).

The presentation also showed how big the weather effect can be in Ontario:

- Peak: as high as 10% for some months (equals 5-10 years of growth for some LDCs)

- Energy: 1-2% weather correction (equals 1-2 years of growth for some LDCs).

The presentation concluded with the following reasons for undertaking weather adjustments:

- Adjustment takes out abnormal weather effects from the actual load, so that
  - actual load is weather corrected
  - rate case is based on weather-normal load
  - rate design is not biased (upward or downward) by extreme weather effects.

In the discussion following the presentation, the larger LDCs were generally experienced with and favourable to the notion of weather adjustments. Two areas of concerns emerged among the other participants:

- There were few known experienced providers of the sophisticated load data weather adjustment services to Ontario LDCs aside from Hydro One's forecasting unit, and Stanley But cautioned his group could not to 90plus weather adjustment within a short period of time. Therefore some type of staggering system would be required. This issue was flagged for further discussion.

- Hydro One would need to recover its costs in providing weather adjustment capabilities to other LDCs. The initial rough estimate for purposes of the cost allocation studies would be a one-time charge of around $2000 per utility. Because a separate computer run was required for each adjustment, the cost would be relatively the same regardless of the size of the LDC. Thus the per customer cost for weather adjustment would be around 20 cents per customer for a utility of 10,000 customers, but increase to around $2 per customer for a utility of 1,000 customers.

- Although weather adjustment of load data was only a "one-shot" expense, some group members wondered what would be the benefit in terms of better cost allocation results to using more costly weather-adjusted load data as an input.

- Even if use was made of the load analysis expertise and costly software already in the possession of Hydro One, to create weather-adjusted load curves of plus minus 10% accuracy would require both a weather adjustment and detailed load shape analysis by rate class to the take into account the other unique circumstances of specific utility (such as appliance saturation and customer mix). Because a separate analysis and computer run would be required for each utility, the per customer total cost for such new load curves would be greatest for the smaller utilities. The question of what was economically sensible to do for the smallest utilities was raised (since several Ontario LDCs are under 1,000 customers in size, and some of them could face one-time costs of $5 per customer or more for new accurate, weather-normalized load curves under the present option).

3. Policy Issues in Weather Adjustment

Paula Zarnett made a presentation which clarified two distinct question existed in this area:

- Firstly, what was the case for weather adjusting load shapes?
  (As noted above, answered in Ontario by evidence peaks can vary by up to10%.)

- Secondly, accepting need for weather adjustment, how should it be done?
  - One approach would be adjust to long-term averages, another to extreme conditions.

As noted in the presentation by Mr. But, there is a third, middle option: an average of extremes. The models currently in wide use in Ontario would, for example, calculate the hottest day in July as the average maximum of July of the past 31 years.

The ensuing group discussion raised several points:

- Many group members felt cost causality should be based on who uses the distribution system on the most extreme day(s); others disagreed, on the grounds cost causality should recognize the multiple goals and features of a distribution system (such as reliability).

- Questions were raised about how clear was the concept of cost causality in practise, as when a system was originally built to serve winter peaking customers but was now used by summer peaking customers [editor's note: the "benefits" principle of cost causality was mentioned by Bill Harper in an earlier session].

- It was cautioned that adjusting to the single most extreme day (instead of the average of the extremes, as is current Ontario practice) would lead to the imposition of significant additional costs upon residential customers. It was felt this was a concern since rate stability was previously accepted as a valid secondary goal of the cost allocation process.

Given the importance of the issue, a further discussion of how to weather adjust was scheduled.

4. New Metering Technology

Paul Elliot (Whitby) did a presentation on a new residential interval metering technology. This system was currently being used by Whitby Hydro, and by a large natural gas distributor in the province.

5. Use of Cluster Sampling

The concerns about the accuracy of these technique in some circumstances was noted (as discussed at page 4-9 of the AEIC Load Research Manual). The group believed the comments regarding "fitness" set out in the presentation on sharing of data would proof applicable here as well.

6. Roundtable discussion of data collection challenges

The group discussed practical problems that may be faced by any LDC wanting to do its own load data collection.

Re Missing Data
The group noted that lost or missing data sometimes occurred during the course of conducting load research. There are many widely-accepted ways to dealing with missing data mentioned in reference works (for example, in IMO materials). It was recommended that when conduct their cost allocation studies, utilities follow a reasonable approach.

Other practical points mentioned:

Re CIS Data
- How to reconcile data dump to billing data
- How to deal with inactive accounts. Will the consumption be picked up?
- How to deal with customers moving in and out - what segment of consumption is kept.

Re Interpretation of Data
Was there anything different happening in the period?
- Special non-annual conventions
- Plant closures or other economic downturns (e.g. due to SARS)
- Snow storms down wires - no or low consumption
- Major breaks or downtimes.

Feeder Connections

- Information on the number and load of various classes of customers on primary and secondary feeders and stations
- This could help allocate distribution costs.

Attendance

Bluewater Power - Kathy Gadsby
Brantford Power - Heather Wyatt
Hydro One - Mike Roger, Stanley But
London Hydro - Ken Walsh
Milton Hydro - Don Thorne
Oakville - Gary Parent
Toronto - Anthony Lam
Thunder Bay Hydro - Cynthia Domjancic
Veridian - Laurie Stickwood
Whitby Hydro - Ramona Abi-Rashed and Paul Elliot

Econalysis - Bruce Bacon
ECMI - Roger White, Andy Bateman
EDA - Maurice Tucci; John Wong
RCS - Mike Mcleod, Peter Ioannou
Upper Canada Energy Alliance - Jim Richardson
Chris Amos
Barker, Dunn & Rossi - Paula Zarnett, Neil Winger
MOE - Takis Plagiannakos
Guest - Dr. Neil Mather

Board Staff:
John Vrantsidis
Neil Yeung