Ontario Power Authority
Toronto, Ontario

Northern York Region Electricity Supply Study
Submission to the Ontario Energy Board
September 30, 2005

Exhibit B
Load Forecast & CDM Options
Northern York Region

Hatch Acres
September 26, 2005

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1 INTRODUCTION

York Region is one of the fastest growing areas in the province. Electricity supply in the region, currently estimated at some 1700 MW, is provided by four local distribution companies: PowerStream Inc (supplying Vaughan, Richmond Hill and Markham); Aurora Hydro and Newmarket Hydro supplying their respective towns; and Hydro One supplying all other towns and villages and the rural areas.

The southern portion of the region is supplied (through PowerStream) by a number of transformer stations connected to the transmission corridor from Cherrywood TS in the east to Claireville TS in the west. While there are concerns with this supply, particularly in terms of transformation, the more critical issue in the region is the supply to the north. Northern York, consisting of Aurora, Newmarket and the Hydro One service area are supplied by a double circuit transmission line running from Claireville TS north across the region to Minden. The line supplies Armitage TS and Brown Hill TS. Both the transmission line and the Armitage transformer station are near capacity, threatening service to the entire service area. Figure 1.1 shows the approximate boundaries of the Armitage TS service area.

In 2003, Hydro One put forward a plan to construct a new double circuit 230 kV transmission line to Newmarket in an existing corridor and build a new transformer station. This plan was met with opposition from the affected municipalities, residents and others with the result that the OPA is undertaking this current study.

The Terms of Reference for this study reference tasks under the load forecast as follows:

"The Consultant will be required to develop and provide forecasts that potentially lead to the conclusion that reinforcements to the existing electricity system are necessary, …."

"(a) Review, assess and reconcile load forecasts already prepared for York Region. Clearly document the assumptions and drivers for the forecast, and indicate the sensitivity to weather conditions (normal or extreme weather). As necessary, prepare additional assessments or scenarios that are relevant to the study.

(c) Identify and consider supply and demand-side options and potential modifications to the transmission and distribution systems in order to address any issues identified in (b). Consider stopgap or temporary operating solutions that are acceptable and can potentially extend the lead times for more enduring solutions."

The complete terms of reference are included as Appendix A.

Forecasts are prepared by each local distribution company for their own use in financial analysis and investment planning. While the immediate concern is the supply of power to the northern portion of York Region, documents from all LDCs in the region were assembled and evaluated. Specifically, the forecasts from Aurora Hydro, Newmarket Hydro, PowerStream, Hydro One and the Independent Electricity System Operator were reviewed for this study. The forecasts display a wide array of forecasting methods ranging from simple trendline growth to sophisticated econometric modeling with an equally wide range of background material for review.

Much of the basic review and evaluation of the LDC forecasts is the result of a subcontract with marketPOWER research inc. The interpretation of their work and the assembly of the forecasts to quantify the problem definition was undertaken by Acres International. The marketPOWER research report, as received, is included as Appendix B.

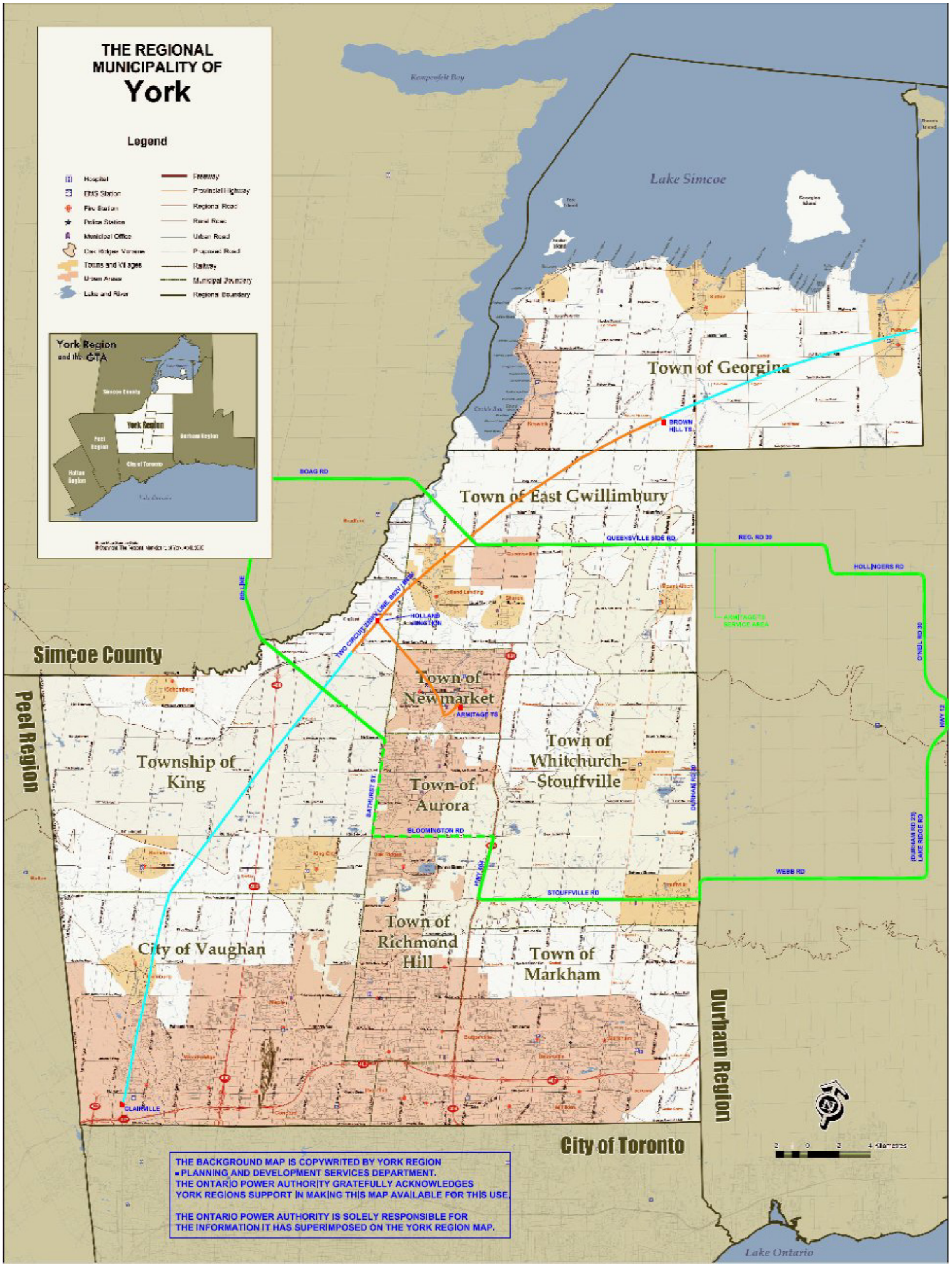


Figure 1.1 – York Region & Approximate Armitage Service Area

2 APPROACHES TO FORECASTING

2.1 Background

Forecasts are typically required for three principal planning functions. A long-term forecast of overall energy and peak demand generation is required for the generation planning component of a long-term investment plan. This forecast requires no geographic detail. A long-term forecast is also required for the transmission planning component of a long-term investment plan. This forecast requires geographic detail to the substation level to allow a reasonable simulation of both the transmission and distribution systems. Finally, a short-term forecast may be required by tariff category and sub-category in the preparation of tariff submissions.

The load forecast process is driven by two essentially opposing concepts. The financial planning function requires a forecast that reflects the amount of energy that because of system constraints can be supplied and consumed, the generation and transmission planning functions require a indication of the amount of energy that might be demanded with few constraints.

2.2 Load Forecasting Context

The ultimate objective of an electric utility is to provide generation, transmission and distribution facilities which will supply power at the lowest feasible cost subject to constraints of safety, reliability and financial integrity. To satisfy this objective it is necessary to plan for a particular level of future consumption. In the overall planning process, the financial implications of the initial load forecast in the form of projected tariff increases are fed back into the power market analysis and a revised forecast is produced.

Electricity differs from most other forms of energy in that it is manufactured, and can be made from almost any other type of energy. Consequently, it is able to draw upon more technical alternatives for generation than any other energy source. The generation of electricity is, by its nature, a capital intensive production process and the choice between alternative modes of generation can be quite different in the short term, which will be based largely on past decisions, and in the long term, which will shape future decisions.

The information required of a load forecast is essentially the maximum power and the total energy to be consumed in the future. In addition, considerable geographic and temporal detail is required by various functions within the utility. Generation planning departments require annual or seasonal data for many years into the future, while operational departments require the same data for only one or two years to determine, for example, fuel requirements. Hourly demand data is used to plan the day-to-day operations of the system.

Load forecasts are also inputs to the financial departments in the areas of tariff policy and generation financing. A given forecast may require additional generation facilities which in turn will necessitate higher tariffs in concert with domestic or international borrowings.

Long Term Forecasts

The decision to build a given generation plant must be made many years before its services are required. Typically 6 to 10 years are required to develop a major hydro or conventional thermal generating facility. The process begins with a long term forecast of expected demands on the system of sufficient detail and extent to allow for accurate generation planning. In view of the lengthy lead times required in the industry and the multiplicity of factors involved in the demand for electricity, it is unrealistic to assume that a single forecast of demand 10 to 15 years in the future will precisely depict the actual consumption level at that time. It is necessary, therefore to continually update a forecast to reflect current trends, technology and consumption patterns. In addition, alternative forecasts are required to test the sensitivity of the proposed generation plan to changes in demand.

Short Term Forecasts

In general, the long term forecast relies on a historic relationship between electricity consumption and aggregate socio-economic indicators. Gross Domestic Product and population are two obvious examples. Short term forecasting on the other hand treats these relationships as the average demand or base load. Temporary deviations from this base are influenced by trends which are hidden in the long run data. The effect of weather and other seasonal components of demand are only relevant in short term forecasts. These factors include, production schedules, agricultural output, day of week and time of day.

Short term forecasts tend to concentrate on the energy aspects of utility operation, such as fuel requirements and equipment utilization. They can also be used to prepare maintenance schedules and develop inter-regional or international power pooling agreements. As in the case of long term forecasting, alternative short term predictions are required to incorporate and to evaluate the effects of uncertainty in the basic elements of the forecast.

Forecast Error

The uncertainty surrounding any forecast and the number of alternative generation and operation sequences available to a utility require that the selection of a particular plan should be based on its performance over the range of forecasts.

No forecast carries with it any guarantee of accuracy, and the occasional forecast can be badly in error. In assessing these bad forecasts it is useful to have available for scrutiny a general statement of the economic climate at the time the forecast was made. A forecast is "bad" only if a better one could have been made with the information on hand at the time. Anyone can make a good forecast with the benefit of hindsight. Similarly, an assessment of the uncertainties associated with the forecast gives its users some appreciation of the risks that they run, and often provides an insight into the cause of any subsequent forecast error.

The risks introduced by an inaccurate load forecast are twofold: inadequate capacity due to underestimating the load or excess capacity due to an overestimate. Inadequate capacity may result in an unreliable supply causing direct financial loss and inconvenience to power customers and increased social costs to the nation. Excess capacity may lead to financial risks to the utility brought about by a high level of investment and inadequate revenues in the short term, and the direct financial loss of power customers due to unnecessarily high power costs in the long term.

The costs of excess capacity are incurred by the utility and passed on to the customer, while the costs of inadequate capacity are borne entirely by the customers and do not directly impact on the utility. For this reason the utility may tend to restrict output, thereby fully utilizing existing equipment and ignoring foregone revenues.

The forecasting effort is preoccupied with minimizing the error and thereby the risks to the utility. To this end the stability of successive forecasts is also a matter of concern. Clearly, if the forecasts were completely accurate, they would not change over time. However, because they can never be this precise, they will fluctuate from one forecast to the next due to new or revised information. Consistent error in either direction for each year or frequent reversal in forecast levels for any one year are disruptive to system development plans and would indicate an underlying problem in the basic data or the forecasting procedure.

2.3 Forecast Framework

Electricity, like most forms of energy is demanded for what it can do not as a product in and of itself, it provides lighting, heating, cooling, cooking, etc. The use of electricity requires appliances, light bulbs, power points, televisions. Electricity, however, has special characteristics, distinct from other energy forms; it is cleaner and more convenient, it is easily controlled and is amenable to a wide variety of functions. For these reasons, electricity has always commanded a substantial premium over other fuels per unit of intrinsic heat value. Despite this pricing, electricity consumption growth has historically been higher than that of total primary energy, implying an increasing role of electricity in the total energy framework.

Electricity is used for a wide range of purposes, each responding differently to factors such as price and income. To accommodate this divergence requires an increasingly detailed analysis in order to derive a properly weighted total demand. The forecasting process thereby can become much more complicated without necessarily becoming more accurate.

Finally, as noted earlier, the demand for electricity is a derived demand. Electricity does not yield utility in and of itself but rather is demanded as an energy input to a stock of capital goods which do yield utility. Therefore, a distinction must be made between short-run and long-run demand for electricity. The short-run demand evolves from the utilization rate of a fixed stock of capital, while the long-run demand is based on the demand for the capital stock itself. A model on this basis requires additional parameters reflecting the stock of electricity consuming capital goods, the price of these goods and the price of alternative goods.

The relative homogeneity of residential consumption, when compared to the industrial or commercial sectors, lends itself to a greater degree of demand analysis. For that reason most studies have either isolated the residential sector or dealt with total electricity consumption without regard to the nature or mix of the consumption.

Despite these potential problems many models of electricity demand have been developed. While definitive numeric data does not emerge because of different models and data sets, several relationships are evident. In the long-run the demand for electricity is sensitive to both price and income changes, in addition the long-run effect is much larger than the short-run, where the demand was generally found to be insensitive to changes in price or income. Sensitivity to price changes in alternative fuels is also observed in the long-run and not in the short-run analysis. Sensitivity to price and income changes was found to vary subject to other parameters such as degree of urbanization, region, household size, climate and level of income. Unfortunately this requires increasingly detailed analysis, in order to arrive at a properly weighted response of total demand.

2.4 Available Forecast Methods

A number of general methods of calculating a forecast are currently employed by public and private utilities. All methods share a common basis in that they originate from two sources: the first source is history, the second is judgment. Most often the component to be forecast is not new; it has a well defined history. The future trend of the component is rooted in this history, its relationship to a collection of external parameters and one or more values based on judgment supplied by the forecaster.

These methods can only, of course, be as reliable as the data they employ. The basic problem in each is the existence of data of sufficient quality and quantity to allow meaningful analysis. The most basic assumption is that the factors which are responsible for past growth will continue to operate unchanged in the future or if change is to occur that its impact is predictable.

The preceding methods rely to a large degree on an analysis of the historical data relevant to a study area. In addition to this form of analysis, there are many topics in load forecasting which cannot be included by use of these strictly numerical methods. The alternative methods are based more on political and social priorities than on historical trends. Two areas which typically fall into this category are load forecasts for rural electrification and those for the early stages of system development.

An additional energy demand which does not lend itself to traditional approaches is that imposed by government decree, such as disaster relief or the need for emergency water supplies. These demands often remain on the regional system long after the emergency has ended, resembling rural electrification schemes more than their original purpose.

In these areas the magnitude of planned system additions is frequently sufficient to produce growth rates of 30 to 50 percent per annum. These rates can obviously not be sustained for more than a few years. In these early stages of development the principal cause of increased consumption, especially in the residential classification, is the number of new connections and not a long-run or background growth rate as would be the case in a larger, more sophisticated system. In addition, the logistical problems posed by terrain or by lack of experienced installation crews may well be the major bottleneck to increased consumption rather than a supply deficit.

Forecasting under these conditions is at best a tenuous exercise which must rely on judgment and experience in similar situations elsewhere. The resulting forecasts often resemble the physical models mentioned earlier, as they are usually based on population, planned connection schedules, per capita consumption levels and other such variables. Again, the forecast will only be as reliable as the data and assumptions input to the analysis.

The following section outlines the basic methods commonly used in load forecasting. A rigorous mathematical treatment for each is not considered here as it is generally available elsewhere.

2.4.1 Time Series Methods

Models in which the basic driving variable is time are examples of the time series method. Time series load forecasting models use only the history of electricity consumption to forecast future growth. Time series models do little to explain the underlying structure of the sector to be forecast. They are dominated by the past and cannot forecast changes unless the circumstances surrounding the change occurred before. The models resemble econometric models in that a variety of equation formats or curves can be applied to the historical data to obtain estimates of future values. They can be as simple as a straight-line projection or as sophisticated as the Box-Jenkins technique.

The fundamental assumption is the claim that the optimal forecasts of future values of a time series are dependent on past observations only, i.e. a mathematical formulation exists which reflects the behaviour of the time series, and which, once established, may be used to forecast values of that series into the future. The primary objective of the analysis, then, is to determine the formulation which will suitably represent the series in question.

They apply numerical analysis tools, such as exponential smoothing and the Box-Jenkins approach, to the historical data to identify trends, seasonal changes, and other patterns. These patterns are then projected into the future to produce a forecast. Exponential smoothing techniques model the data in terms of three factors: level, trend and seasonality. It is a more sophisticated form of a simple trend analysis. Box-Jenkins is an ARIMA (auto-regressive integrated moving average) technique; that is, it estimates the relationships by regressing the series on itself, after first using moving averages to smooth the series.

There are essentially three levels of time series models. The simplest is the application of a growth rate or a moving average to the historical data and the extrapolation of that growth into the future. A slightly improved model is the exponentially weighted moving average which assigns higher value to the more recent observations. The highest level is the autoregressive, moving average model typified by the Box-Jenkins technique. Its advantages are that past forecast errors are taken into account in both the estimation and forecast stages, and that confidence intervals are provided with the point forecasts.

Time series models cannot have more information about the series under investigation than is contained in the series itself. The analytical tools only identify patterns in the historical data which can describe previous behaviour, and cannot incorporate such other information as the level of economic activity in an area, or its population growth, or the incidence of new industries entering the area.

For this reason, time series-based forecasts are considered reliable only for a relatively short time horizon, typically one to two years. After that, the underlying dynamics of the system being modelled are likely to change, and time series methods cannot model such changes. Longer-term forecasts must take into account the possibility of fundamental changes in the factors driving the variable or variables being forecast.

The main advantage of the time series approach is the expected increase in forecast accuracy, particularly in the short run, compared to forecasts based on other methods. The time series analytical techniques make fuller use of the information contained in the history of sales than does simple trend analysis. An additional benefit of using time series techniques is that they can readily produce month-by-month forecasts, including seasonal variations, for use in short-term planning.

Successful time series models usually require that the data be transformed or adjusted. The goal of the transformations is to get the data series to meet certain technical criteria. Possible transformations include moving averaging, other smoothing techniques, and Box-Cox transforms (taking square roots or logarithms). The choice of transform is dictated by the nature of the data series and by the time series technique to be used.

The time series may also be adjusted for anomalous events in the data. For example, if a strike affected the data over the period, the historical data should be adjusted for the strike. If they are not, the time series models will assume that the reduction in activity during the strike was part of the historical pattern, and will seek to explain it as part of the history. Several techniques are available for adjustment; they all amount to estimating, from the data, what would have happened during the affected period, and substituting those data for the actual experience.

Building time series models therefore requires the analyst to deal with a number of issues. The analyst must decide on the transformations, if any, to be used on the data; on whether the data need to be adjusted; and on the time series technique to be used. The result will be a model of the time series under analysis which will both explain the history of the variable and forecast its future.

2.4.2 Econometric Methods

Econometric methods seek to describe the behaviour of variables by identifying relationships between them. While time series analyses use information from only a single variable, the one being analysed, econometric methods try to estimate relationships between multiple variables. In load forecasting, electricity demand is typically related to variables such as electricity price, economic activity, and population.

Econometric models relate electricity consumption to other variables or levels of activity in the economy. The relationships are determined on the basis of the observed interactions between the variables over a number of years. They do, therefore, include the effects of energy efficiency. However, these effects will only be those which are implicit in the data, for example that arising from increased prices. This price-induced efficiency is different from a strategic efficiency implemented as a result of policy changes such as new standards, advertising or incentives. Econometric models measure changes in electricity demand but provide no ready means of isolating nor forecasting the source or sources of the change. In addition, the changes in energy efficiency determined within an econometric model and typically expressed as price or income elasticities include all past technological, behavioural and external changes. Forecasts based on these elasticities will perpetuate these relationships into the future.

Econometric models are based on the observed behavioural relationships between electricity used and selected economic variables, such as Gross Domestic Product, population and price. These relationships are internal to the model, derived from a statistical analysis of the historical data and cannot be easily changed. Econometric models are best used as predictive models as they predict the likely energy outcome derived from the behavioural relationships associated with the forecasts for the economic variables regardless of the background to these forecasts.

To determine what relationships to test, econometric methods start with a model of the activity being described. From that model, an hypothesized relationship or set of relationships to be tested can be derived. These take the form of hypotheses about variables which are expected to be associated with each other. The relationship to be tested takes the form of an equation, where the variable to be explained (the dependent or explained variable) is expressed as a function of the variable or variables thought to drive the dependent variable (these are the independent or explanatory variables).

Finally, econometric testing requires gathering data to represent both the dependent and independent variables and testing statistically whether the hypothesized relationships hold. In many cases, more than one data series can be found that will represent the same independent variable. The econometrician must then choose the data series which best explains the historical data.

Econometric models typically consist of several equations relating economic or demographic variables to the component to be forecast. These models assume that there is a strong link between the component to be forecast and its explanatory variables, a link which is more than merely statistical. Given that this linkage exists, the forecasting and judgmental effort is transferred to the explanatory variables. Forecasts of Gross Domestic Product, population, etc. must be derived or obtained with a greater expected accuracy than a direct forecast of electricity consumption would have provided.

The major limitation to econometric models is that they tend to overestimate the future as they do not necessarily recognize physical limits unless these limits have been explicitly included in the model equations. An example of this restriction would be a model which forecast increasing domestic consumption per household in an economy without the capability of supplying the appliances basic to this growth

The estimated econometric model also describes the structure of the relationship; that is, it shows exactly how the variables are estimated to depend on each other. The estimated equation produces a specific quantitative relationship between the dependent and the independent variables. The equation gives, for any values of the independent variables, a precise value of the dependent variable. It therefore describes precisely how the dependent variable is estimated to respond to changes in the independent variables.

The estimated models can then be used for forecasting. The estimated equation gives a value of the dependent variable for any values of the independent variables. If the values of the independent variables represent forecasts, the computed dependent variable will be a forecast.

2.4.3 End-Use Methods

The above two methods are aggregate techniques. That is the analysis views electricity consumption for an entire region or consumption category. End-use analysis takes a bottom-up approach to electricity use. It starts from a disaggregated view of energy demand, attempting to understand the behaviour of a single consumer. It then aggregates to total demand by adding up the usage of the consumers in as many categories as can be defined and quantified.

These physical models (often called engineering models) consist of simple equations relating, for example, number of customers, appliance saturation and appliance energy use. Given a forecast of each of the components, the total energy use is easily computed. The model is, however, based on a detailed survey and an accurate evaluation of existing customer capital stock. This requires a large database, an understanding of trends in the growth of the capital stock and a constant monitoring of new technology. This becomes the major problem with physical models, for without the allowance for new technology, the models will tend to underestimate the future in the presence of additional energy consuming devices and to overestimate in the presence of energy saving devices.

One clear advantage of an end-use model is that it can explicitly include demand side management and energy efficiency issues in the forecasting exercise. The analysis can postulate changes in energy efficiency and then trace these changes through the model to define their impact on overall demand. Electricity is not purchased for what it is but rather for what it can do. End-use models describe this utility in terms of the consumption of electricity per appliance or per unit of output in an industrial context. End-use models therefore, by their very nature include explicitly those relationships which econometric model treat implicitly, that is, changes in the efficiency levels of appliances, changes in the number and use of appliances and the introduction of new appliances or operations.

End-use models are based on the known physical relationships between electricity consumption and electricity consuming appliances. These models therefore can react to physical changes in a manner which cannot be accomplished within econometric models. End-use models are less useful as predictive models because the background to the physical relationships, i.e. the source of the changes in the numbers and type of appliances as well as their intensity of use, must be specified by the analyst. These are assumed within the behavioural relationships of the econometric model. The end-use model does, however, allow an estimate of the impact of a wide range of alternative developments in technology and energy efficiency. Thus, while this category of model should in theory provide better estimates of energy consumption, the database required to accurately define the model may well be beyond the resources available to produce the forecast.

End-use forecasts consider electricity use not as an end in itself, but as a means to achieve other consumer services. In other words, the demand for electricity is a derived demand; electricity is not consumed for itself but rather for what it will accomplish by being consumed (cooking, heating, lighting, etc). For example, a light bulb provides illumination; an electric motor running a conveyer belt provides transportation. These services could be provided in other ways; in most end uses, electricity faces competition from some other energy source.

End-use load forecasts gather information on the multiplicity of end uses in an electricity service area, and compile them into a comprehensive view of the electricity use. Then a forecast is produced by forecasting the future for all the electricity end uses, as well as projecting what new uses will occur during the forecast period.

The advantage of an end-use forecast is that it requires much better understanding of the way that customers use electricity. Its main disadvantage is that it requires a very large amount of data (often difficult if not impossible to obtain) and many separate forecasts, since each use must be forecast individually.

Thus, econometric models lead to decisions which address how utility planners intent to supply the expected demand whereas end-use models focus on alternative policy directives which could modify that level of expected demand.

2.4.4 Input/Output Models

In forecasting load for specific industries, an input/output approach can often be used. This approach represents the production process in terms of all the inputs it needs, such as labour, capital equipment, materials, and energy (the input) relative to the amount produced (the output). For each unit of output of an industry, the input/output model specifies an exact amount of each input the industry needs. Input/Output models can represent the production process in some detail, including alternative production methods. Electricity is treated as one input in the process.

Input-output models are detailed inter-industry models which have as one of their main attractions a built-in consistency with the technological relationships between industries. The model then provides the energy requirements to produce a given composition of final goods in the economy. The structure of the models is based on cross-sectional rather than time series data. For this reason, the coefficients are by necessity fixed in time and provide a detailed picture of the relationships only at that point in time. In long term forecasting the coefficients must be dynamic, that is adjusted to accommodate technological changes, improvements in energy use efficiency and other factors such as interfuel substitution.

The vast amounts of reliable data for model estimation and the frequent need to modify the model in response to changes in the structure of the economy will preclude the construction of such comprehensive models in most situations.

3 AVAILABLE FORECASTS

As noted in the introduction, forecasts are prepared by each local distribution company for their own use in financial analysis and investment planning. While the immediate concern is the supply of power to the northern portion of York Region, documents from all LDCs in the region were assembled and evaluated. Specifically, the forecasts from Aurora Hydro, Newmarket Hydro, PowerStream, Hydro One and the Independent Electricity System Operator were reviewed for this study. The forecasts display a wide array of forecasting methods ranging from simple trendline growth to sophisticated econometric modeling with an equally wide range of background material for review.

3.1.1 PowerStream

The PowerStream forecast utilises two approaches in its evaluation of load growth. The first approach starts with projections of population and employment growth, and then translates them into forecasts of additional electricity load. The second approach is based on observed time trends in load. The forecast horizon is 2014.

In the first approach, PowerStream begins with population forecasts provided by Hemson Consulting Ltd for each of Richmond Hill, Vaughan and Markham. For the PowerStream service territory, the total population is projected to rise from 522,622 in 2001 to 623,700 in 2006, and then to 811,000 by 2021. This means that between 2005 and 2021 there might be an estimated additional 41,000 housing units in Vaughan, 33,400 in Markham and 24,500 in Richmond Hill. These housing growth figures are assessed at 3 kW (3.3 kVA) per housing unit for the electrical forecast.

Corresponding employment projections (also provided by Hemson) from a base of 273,445 in 2001 are 343,510 in 2006 and 473,270 in 2021. These figures are translated into a projected average growth of 551,795 square meters of nonresidential space per year. An assumption of 0.08 kVA per additional square meter is made.

Using the above assumptions, results in an average addition of 66 MVA per year. In fact, a constant additional load of 66 MVA in every year is projected for the period 2005 to 2014. This results in an additional 660 MVA over the ten-year period and an annual average growth of 3.6 percent from 2003 to 2014.

In the second approach, PowerStream looks at the growth in the yearly peak between 2003 and 2004. The annual growth rate (after adjustment for weather) turns out to be 4% and this rate is carried through to 2008. From 2009 to 2014 it is reduced to 3% per year. CDM is cited as the reason for the reduction.

In the end, the PowerStream forecast report opts for the trend method (second approach) because it is more “conservative” and because of “positive historical experience”. The PowerStream forecast also provides low and high forecasts using +/- half of the base forecast rate. No justification of these high and low growth rates is provided.

On the basis of the trend method the load for the entire PowerStream service area rises from 1,357 MW in 2003 to 1,971 MW in 2014. This is an annual average growth of 3.45 percent.

Tables 3.1 and 3.2 display the historic and forecast peak demands, respectively, for the PowerStream service area.

3.1.2 Aurora Hydro

The Aurora analysis evaluates five forecast methods. The first three are trend-based. The fourth makes use of population/employment projections that eventually translate into forecasts of additional electricity load. The fifth correlates load growth with population growth. The chosen final forecast most resembles the results obtained by the fourth method. The forecast time horizon is 2028.

Method 1 employs a linear trend technique. Using the annual averages of past monthly system peaks for 1993 to 2004, annual growth of 1.875 MW per year is forecast. The use of annual averages rather than single annual peaks removes seasonality. This method forecasts an additional 1.875 MW per year out to 2028.

Method 2 begins by calculating average historical growth rates of annual peaks. It uses these as the basis for a forecast of 2.3% growth per year up to 2013. On the view that growth will be tempered thereafter, the rate is then reduced to 2.00 % per year until 2028.

Method 3 takes the natural logarithms of the annual peaks and calculates the associated historical growth rates. This results in a forecast rate of growth of 2.68% per year over the whole of the forecast period.

Method 4 is an end-use forecast. Customers are divided into three groups: residential, general service < 50 kW and general service > 50 kW. Residential customers represent 38% of kWh sales, general service < 50 kW customers 9% and general service > 50 kW customers 53%. For industrial and commercial load growth, the key is land development. The forecast of non-residential load relies on square footage forecasts, which as in the case of PowerStream originate with Hemson Consulting Ltd. The electrical forecast is based on a factor of 2.8 W per square foot (0.030 kW per square meter) for < 50 kW customers and 13 W per square foot (0.137 kW per square meter) for > 50 kW customers.

Residential growth is based on a forecast of an additional 2580 housing units over the five-year period 2006 - 2011. This declines to 800 additional units in 2026 - 2031. These housing growth rates are again Hemson forecasts. For translating them into residential peak demand, a factor of 3.5 kW per unit is used between 2004 and 2006, 3.2 kW per unit between 2006 and 2011 and 2.9 kW per unit thereafter. A notation in the forecast report tables suggests that these reductions are an allowance for DSM.

"Natural growth" (for existing customers, that is) is forecast to be 0.75 % per year of the system's maximum summer peak, based on the industrial component of the aggregate load.

Method 5 uses a ratio of kW to population of 1.82 to forecast peak demand until 2028.

The above five methods result in a range of projected demands, from 115 MW (Method 2) to 135 MW (Method 4) by 2028. In the end, the Aurora report provides and recommends a forecast very close to the results of Method 4, the most sophisticated of the five methods. The forecast, however, is captured as a 3.5 percent growth rate from 2005 to 2013, then 1.8 percent beyond 2013. In addition the initial value for the forecast (2005) is adjusted to "discount anomalies" introduced into the data based on 2003 and 2004 being unusual summer conditions.

Tables 3.1 and 3.2 display the historic and forecast peak demands, respectively, for Aurora Hydro.

3.1.3 Newmarket Hydro

The Newmarket forecast evaluation explores two methods. The first uses growth rates of population calculated from Hemson population projections. Based on the existing service territory of Newmarket Hydro, it recognizes that the introduction of new geographic areas of service will be severely limited beyond 2015. This is referred to as being "landlocked". The forecast is based on the following annual population growth rates: 4% from 2006 to 2010; 2% from 2011 to 2013; 1% from 2014 to 2028. As in the case of Aurora, the forecast time horizon is 2028.

Newmarket Hydro's preferred peak demand forecast is a trend forecast that projects a 3.51% annual growth rate from 2006 to 2015. This is based on the observed growth rates from 2001 to 2004, with 2.8% growth per year attributable to an increase in new customer sales and 0.7% to higher sales to existing customers. The annual growth in peak demand is projected to fall to 1% per year in every year of the period 2016 to 2028 - 0.5% per year for new customer sales and 0.5% per year for growth of existing customer sales.

The historic and forecast summer peaks for Newmarket are included in Tables 3.1 and 3.2, respectively.

3.1.4 Hydro One Networks Inc.

The Hydro One service area forecast is a residual forecast based on an average growth rate for all sales in the region less specific sales in Aurora and Newmarket. For the forecast at Armitage TS, Hydro One first forecasts the load growth for Aurora, Newmarket, Markham, Vaughan and Richmond Hill. The overall growth rate for the aggregate of these five utilities is applied to the base year Armitage TS sales. Hydro One then reduces this aggregate forecast for Armitage TS by their forecast for Aurora and Newmarket and represents the remainder as the forecast for the Hydro One portion of the load supplied through Armitage TS. This service area includes Stouffville, Ballantrae, Mount Albert, Sharon and Queensville in York Region and Bradford-West Gwillimbury in Simcoe County. The Town of Georgina, which includes Keswick, Sutton and Pefferlaw is served through the Brown Hill TS and does not appear to be included in this forecast process.

The load forecasts for the five utilities are based on econometric models linking load growth to demographic, economic and weather variables. The specifications for the individual utilities are as follows:

- For *Aurora*, the logarithm of the Aurora load is regressed on the logarithm of the Ontario load, the logarithm of the lagged Aurora load and the logarithm of the Aurora population.
- The *Newmarket* load is regressed on the Ontario real disposable income, the Newmarket population, and a dummy variable.
- The summer *Markham* load is regressed on Ontario real disposable income, the Markham population, cooling degree days and a dummy variable.
- The summer *Richmond Hill* load is regressed on cooling degree days, the lag of cooling degree days, Ontario GDP, and the lagged load of Richmond Hill.
- The *Vaughan* load is regressed on Ontario GDP and the number of households in Vaughan.

The population growth rate for York is assumed to be 3.3% per year for 2004 – 2015, with higher growth rates in earlier years. The number of households is expected to grow at a rate of 4.6% per year. Ontario personal disposable income and Ontario GDP are forecast to grow at an average rate of 3.5% and 3.3% per year, respectively. No further background on these forecasts or on the forecasts for the other transformer stations on the Claireville-Minden transmission line (Beaverton, Brown Hill and Lindsay) was available.

Hydro One forecasts obtained in March 2004 project the load growth at Armitage TS at 3.1% per year over the period 2003 – 2015. This compares to the growth rate of 3.0 percent per year (2003 to 2013) presented in the 2003 York Supply Study. Tables 3.1 and 3.2 display the available Hydro One historic and forecast data by principal TS on the Claireville to Minden transmission line. At the request of one of the York Region municipalities, Hydro One has recently (Sept 2005) reviewed the Armitage forecast. The review resulted in no change to the underlying components of the forecast.

3.1.5 Independent Electricity System Operator

The Independent Electricity System Operator (IESO) makes 18-month forecasts on a quarterly basis and 10-year forecasts on an annual basis. For the 10-year horizon, zone forecasts for Ontario are provided for energy (GWh) and peak demand (MW). In fact, IESO does two types of peak forecasts, by zone: coincident with the Ontario system and non-coincident. Our focus is on zone non-coincident peak demand because this is more closely tied to the regional peaks.

Two of IESO's zones are of interest from the point of view of York Region: Essa, which contains the northern part of York and extends to the Ottawa River, and Toronto, which contains the southern part of the region.

For each zone, the forecasting model is a single equation regression model where the dependent variable is hourly load for each day of the year. The independent variables include weather variables (dry bulb temperature, dew point temperature, wind speed and cloud cover), sunrise and sunset times, calendar variables (day of week, holiday information), employment, number of households, and a trend variable. Historical household data for a zone was constructed using Statistics Canada census subdivision information, and housing starts (for Ontario and relevant Census Metropolitan Areas from Canada Mortgage and Housing Corporation. Statistics Canada employment estimates for relevant economic regions provide the historical data for the zone. The purpose of the trend variable is to capture zone-specific trends such as increased penetration of air conditioning in the summer.

For the first two years of the IESO forecast, employment and household projections are based on Canadian chartered bank economic forecasts. Historical relationships between the banks' projections and zone employment and household variables are developed. For the remaining eight years of the ten-year forecast, the midpoint Statistics Canada population projection (Scenario 3) for Ontario forms the basis for projecting employment and households. Historical relationships between employment, households and population, in conjunction with historical shares of growth in specific zones, lead to projections of households and employment for the zones.

The IESO base forecast assumes "normal weather", as derived from historical data (across 30 years). The daily weather variables are ranked within each week from the historical record and the average for each of the ranked days is calculated. (For example, a median for the coldest day, determined by impact on load, followed by a median for the second coldest, down to a median for the seventh coldest, form the basis for constructing a "normal" week.)

IESO defines two other weather scenarios. An extreme scenario is based on historical weather but uses minima and maxima rather than averages. This technique, accounting for extreme weather, can be used for peak demand forecasts. A second "Load Forecast Uncertainty" scenario is based on one standard deviation of the weather elements. The calculation is in terms of temperature, wind speed or MW contribution, depending on the application. (While these weather scenarios are relevant for peak demand forecasts, the scenarios have no relevance in terms of meaningful extreme week load shapes or kWh projections.)

For the Essa zone, the projected annual growth in winter load (from January, 2005, to January, 2014) is 0.85% per year, and the annual growth in summer load (from July, 2005 to July, 2014) is 0.31% per year. For the Toronto zone the projected annual growth in winter load (from January, 2005, to January, 2014) is 0.73% per year, and the annual growth in summer load (from July, 2005, to July, 2014) is 1.28% per year.

The large service area for the Essa Zone precludes it use directly in the current load forecast review. However, using the IESO model, the forecaster is able to quantify the impact of variation in weather on the total load. For example, calculations are provided for the megawatt impact on the Ontario system of a 1 degree Celsius increase in the summer. Using their model, such calculations could also be done for individual zones. However, without a great deal of additional data collection it is unlikely that the IESO forecast model can be easily applied to the York Region service area alone.

Table 3.1 - York Region Historic Peak Demands (MW)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	1992 - 2003
PowerStream Service Area														
Vaughan	280.0	312.0	325.0	338.0	351.0	380.0	413.0	440.0	473.0	560.0	580.0	614.0	n.a.	7.4%
Markham	292.0	322.0	339.0	347.0	331.0	355.0	374.0	405.0	378.0	462.0	465.0	479.0	n.a.	4.6%
Richmond Hill	136.0	151.0	164.0	174.0	164.0	176.0	188.0	213.0	201.0	238.0	250.0	264.0	n.a.	6.2%
PowerStream	708.0	785.0	828.0	859.0	846.0	911.0	975.0	1,058.0	1,052.0	1,260.0	1,295.0	1,357.0	n.a.	6.1%
Growth (%)		10.9%	5.5%	3.7%	-1.5%	7.7%	7.0%	8.5%	-0.6%	19.8%	2.8%	4.8%		
Northern York Region														**1993 - 2004**
Aurora	--	55.4	57.7	60.3	60.8	64.6	67.7	73.0	72.1	82.6	76.0	72.3	69.8	
Growth (%)			4.1%	4.6%	0.8%	6.3%	4.8%	7.9%	-1.2%	14.5%	-8.0%	-4.8%	-3.5%	2.1%
Newmarket	--	88.3	91.2	96.2	96.0	103.5	111.7	117.4	115.8	131.7	135.5	137.4	133.0	
Growth (%)			3.2%	5.5%	-0.2%	7.8%	7.9%	5.1%	-1.3%	13.8%	2.9%	1.4%	-3.2%	3.8%
Bradford [a]	--	--	--	14.8	15.6	16.4	17.4	21.2	21.6	23.2	25.8	27.0	27.2	
Growth (%)					5.4%	5.1%	6.1%	21.8%	1.9%	7.4%	11.2%	4.7%	0.7%	7.0%
Hydro One														
Armitage	--	--	--	--	--	--	--	--	--	--	351.0	357.9	n.a.	
Brown Hill	--	--	--	--	--	--	--	--	--	--	42.8	45.1	n.a.	
Beaverton	--	--	--	--	--	--	--	--	--	--	57.7	60.7	n.a.	
Lindsay	--	--	--	--	--	--	--	--	--	--	67.0	66.0	n.a.	
Keele Valley NUG	--	--	--	--	--	--	--	--	--	--	-30.0	-30.0	n.a.	
Sub-Totals														
HONI Srv Area [b]	--	--	--	--	--	--	--	--	--	--	113.7	121.2	n.a.	
Load on 44 kV bus [c]	--	--	--	--	--	--	--	--	--	--	351.0	357.9	n.a.	
Load on T/S [d]	--	--	--	--	--	--	--	--	--	--	321.0	327.9	n.a.	

a - Bradford-West Gwillimbury is in Simcoe County but is supplied from Armitage TS.
b - HONI Service Area defined as HO Armitage value less Aurora, Newmarket and Bradford-West Gwillimbury
c - Total load served by 44 kV bus at Armitage TS.
d - Armitage load less generation provided by Keele Valley NUG.

Table 3.2 - York Region Forecast Peak Demands (MW)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2003 - 2014
PowerStream Service Area														
Vaughan	614.0	638.6	664.1	690.7	718.3	747.0	769.4	792.5	816.3	840.8	866.0	892.0	918.7	3.4%
Markham	479.0	498.2	518.1	538.8	560.4	582.8	600.3	618.3	636.8	655.9	675.6	695.9	716.7	3.4%
Richmond Hill	264.0	274.6	285.5	297.0	308.8	321.2	330.8	340.8	351.0	361.5	372.4	383.5	395.0	3.4%
PowerStream	1,357.0	1,411.3	1,467.7	1,526.4	1,587.5	1,651.0	1,700.5	1,751.5	1,804.1	1,858.2	1,914.0	1,971.4	2,030.5	
Growth (%)		4.0%	4.0%	4.0%	4.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.4%
Northern York Region														
Aurora	72.3	70.0	78.0	80.7	83.6	86.5	89.5	92.6	95.9	99.2	102.7	104.6	106.4	
Growth (%)		-3.2%	11.4%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	1.8%	1.8%	3.3%
Newmarket	137.4	133.0	142.2	146.9	152.1	157.4	162.9	168.6	174.6	180.7	187.0	193.6	200.4	
Growth (%)		-3.2%	6.9%	3.3%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.2%
Bradford [a]	27.0	27.2	28.3	29.4	30.7	31.9	33.1	34.3	35.3	36.7	37.9	39.1	40.4	
Growth (%)		0.7%	4.0%	3.9%	4.4%	3.9%	3.8%	3.6%	2.9%	4.0%	3.3%	3.2%	3.3%	3.4%
Hydro One														
Armitage	357.9	369.8	382.1	394.9	408.0	421.6	434.7	448.2	462.2	476.5	491.3	506.6	516.2	3.1%
Brown Hill	45.1	45.6	46.0	46.5	46.9	47.4	47.9	48.4	48.8	49.3	49.8	50.3	50.8	1.0%
Beaverton	60.7	61.3	61.9	62.5	63.2	63.8	64.4	65.1	65.7	66.4	67.0	67.7	68.4	1.0%
Lindsay	66.0	66.7	67.3	68.0	68.7	69.4	70.1	70.8	71.5	72.2	72.9	73.6	74.4	1.0%
Keele Valley NUG	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	
Sub-Totals														
HONI Srv Area [b]	121.2	139.6	133.6	137.9	141.7	145.8	149.2	152.6	156.5	159.9	163.7	169.3	169.0	2.8%
Load on 44 kV bus [c]	357.9	369.8	382.1	394.9	408.0	421.6	434.7	448.2	462.2	476.5	491.3	506.6	516.2	3.1%
Load on T/S [d]	327.9	339.8	352.1	364.9	378.0	391.6	404.7	418.2	432.2	446.5	461.3	476.6	486.2	3.3%

a - Bradford-West Gwillimbury is in Simcoe County but is supplied from Armitage TS.
b - HONI Service Area defined as HO Armitage value less Aurora, Newmarket and Bradford-West Gwillimbury forecasts.
c - Total load served by 44 kV bus at Armitage TS.
d - Armitage load less generation provided by Keele Valley NUG.

4 FORECAST ASSESSMENT

As noted in various sections above, there are a number of specific drivers which are important to the development of a forecast of electrical requirements. The most important of these are population growth, economic growth, electricity prices, weather, and conservation and demand management.

4.1 Population Growth

York Region is one of the fastest growing areas in the province. From 1996 to 2001 total population in the region increased by 23 percent. This is an annual average growth rate of approximately 4.2 percent. Over the same period, the number of households increased by an average of 8.2 percent per year indicating an overall reduction in the number of occupants per household. As electricity use would tend to respond more to the number of households than the population, we would expect that electricity demand could exceed population growth.

Within York Region, population and population growth is concentrated in the three southern municipalities. Population growth (1996-2001) for the four municipalities in the Armitage TS service area is approximately 2.5 percent per year.

Although population and housing forecasts were available to all utilities through the various studies of Hemson Consulting Ltd, only Aurora includes them in their forecasts. The Hydro One forecasts for the individual utilities include population relationships although the source of the forecasts are not cited.

4.2 Economic Growth

Similarly, growth in employment and household income in York Region exceeded national and provincial averages. However, with the exception of Aurora, none of the forecasts explicitly include these variables in their analysis. The Aurora forecast would capture this growth through the Hemson Consulting Ltd estimates of nonresidential floor space. The Hydro One utility forecast include provincial but not regional economic activity.

4.3 Electricity Prices

Given the recent mandated stability in electricity prices in Ontario, there is unlikely to be any significant price relationship to electricity demand. Future price changes are less certain and one would expect that the introduction of time-of-use pricing could have an impact on demand. An increase in the electricity price at peak times would be expected to reduce consumption during that time period and shift many nonessential consumption activities to the non-peak period. It is uncertain whether time-of-use pricing will reduce overall energy consumption but it would be expected to reduce peak demand. None of the utility forecasts include an explicit price component.

4.4 Weather

Weather or more precisely extreme weather, has a significant impact on peak demand, both winter heating and summer cooling. Varying approaches to weather adjustment are used in the York Region forecasts prepared by Hydro One and IESO.

The Hydro One utility forecasts for Markham and Richmond Hill include a relationship to cooling degree days, however, this approach is perhaps more significant in terms of energy demand rather than peaks. The Hydro One base data for Armitage TS are weather corrected before being included in the forecast process. The Armitage forecast is, therefore, a weather normal forecast.

A review of recent (2005) readings at Armitage shows a high correlation between the readings and the forecast values. This would suggest that although 2005 is one of the hottest summers on record, the energy readings are more reflective of a normal-weather summer. It is now known, however, that in anticipation of supply problems at Armitage, Hydro One temporarily transferred some 25 to 30 MW of Armitage load to the Brown Hill TS. This transfer is approximately equal to the incremental peak expected of the extreme weather.

The IESO forecast is the only forecast[1] reviewed which addresses in detail the impact of weather (as measured by temperature, humidity, wind speed and cloud cover) in its forecasts or peak. The other half of the weather relationship requires that the historic data for a utility be adjusted to remove the effects of past extreme weather events. This weather-corrected data would then be used to produce a normalised forecast. The IESO analyses suggest that the actual peak demand can exceed the weather corrected value by up to 12.7 percent.

In a local supply area such as Northern York Region, supply facilities must meet the demand requirements during periods of extreme weather and therefore, weather normalized forecasts, though useful in predicting long-term average growth, understate the potential demand requirement by from 10 to 15 percent.

4.5 Conservation and Demand Management

The PowerStream forecast reduces its long-term growth rate from 4 percent to 3 percent in 2009 on the basis of CDM. The Aurora forecast reduces the power consumption for new housing to incorporate DSM. The other forecasts make no allowance for conservation and demand management and none explicitly include the government-mandated 5 percent reduction by 2007.

4.6 Adequacy of the Available Forecasts

While none of the reviewed forecasts include all of the factors and issues that one might wish to see in an electricity energy and peak demand forecast they do present a reasonable estimate of near-term growth. York Region has demonstrated rapid growth over the past decade, a growth rate that is unlikely to decline significantly in the next 5-10 years. In addition to growth in the larger communities, specific population growth is also expected at Queensville, Stouffville and Ballantre in the Armitage TS service area and at Keswick in the Brown Hill TS service area.

For purposes of this current study an estimate of the future loading on the Claireville to Minden Transmission line and the loading at Armitage TS are required. The loads at Armitage TS are already at near critical levels when measured against the load carrying capacity of the transmission line, the thermal capacity of the station and the number of feeder positions. These loads are such that even modest growth is of concern.

The available forecasts for Armitage, both in terms of the transmission line and the transformer loading, display annual growth of 3.1 to 3.3 percent over the period from 2003 to 2015. Growth in the principal identified components of the load at Armitage, namely, Aurora, Newmarket and Bradford-West Gwillimbury show similar levels of annual growth (3.2 to 3.4 percent).

Pricing and CDM initiatives to reduce the anticipated load in Northern York Region are unlikely to be in wide-spread implementation for several years. Even with a 5 percent reduction in 2007, as mandated, an extreme weather event could still increase the peak by over 12 percent for a

[1] - The PowerStream forecast adjusted the 2003-04 growth rate for weather before applying it to subsequent years

immediate net increase of over 6 percent. A detailed discussion of the current CDM initiatives in the utilities of York Region are presented in Section 5.

The transformer and transmission line loadings from Table 3.2 are repeated below in Table 4.1. The table also includes the impact of the mandated 5 percent reduction in 2007 and a band showing the effect of a 12 percent increase due to extreme weather in any year. The data for the Armitage 44 kV bus loading is displayed in Figure 4.1 and that for the Armitage transmission line in Figure 4.2.

Table 4.1 - Armitage TS Load Estimates

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load on 44 kV bus													
Base Forecast	357.9	369.8	382.1	394.9	408.0	421.6	434.7	448.2	462.2	476.5	491.3	506.6	516.2
CDM reduction (5%)	357.9	369.8	382.1	394.9	387.6	400.5	413.0	425.8	439.1	452.7	466.7	481.3	490.4
Extreme Weather	400.8	414.2	428.0	442.3	434.1	448.6	462.5	476.9	491.8	507.0	522.7	539.0	549.2
2005 Observation			406.5										
Load on T/L													
Base Forecast	327.9	339.8	352.1	364.9	378.0	391.6	404.7	418.2	432.2	446.5	461.3	476.6	486.2
CDM reduction (5%)	327.9	339.8	352.1	364.9	359.1	372.0	384.5	397.3	410.6	424.2	438.2	452.8	461.9
Extreme Weather	367.2	380.6	394.4	408.7	402.2	416.7	430.6	445.0	459.9	475.1	490.8	507.1	517.3
2005 Observation			376.5										

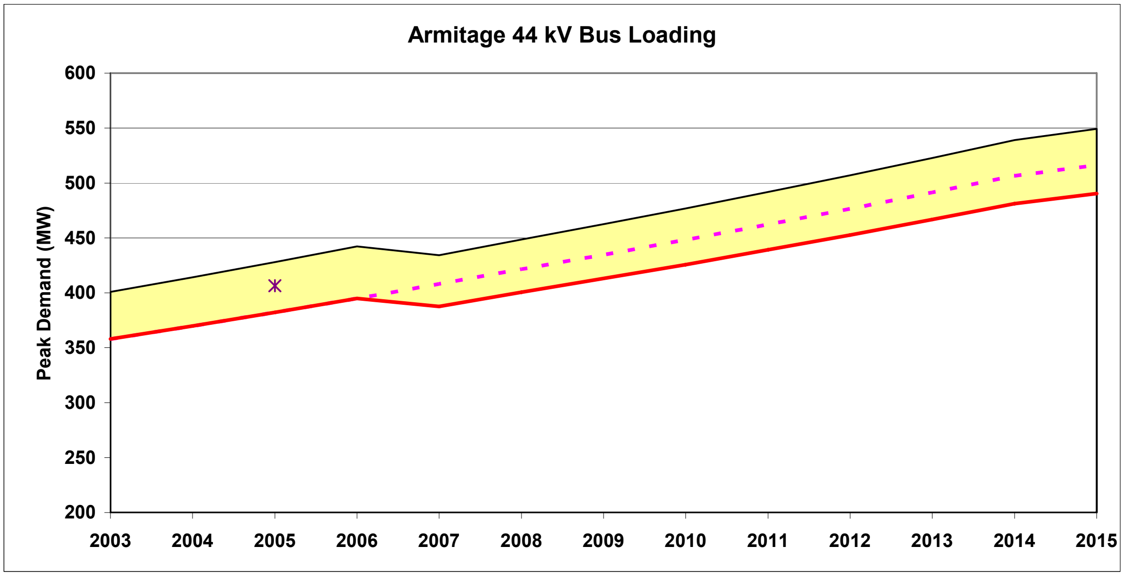


Figure 4.1 – Forecast Band for Armitage 44 kV Bus Loading

where, dotted line is the base forecast
lower line includes the impact of a 5% CDM reduction
band shows possible increment for extreme weather
asterisk shows approximate Armitage load without temporary transfers to Brown Hill TS

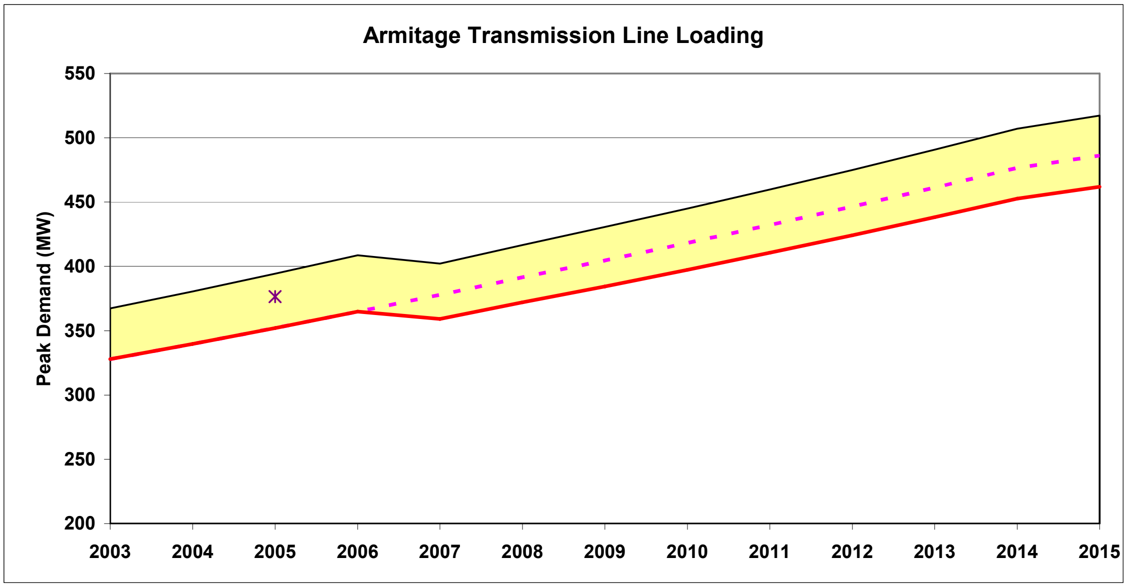


Figure 4.2 – Forecast Band for Armitage Transmission Line Loading

where,
- dotted line is the base forecast
- lower line includes the impact of a 5% CDM reduction
- band shows possible increment for extreme weather
- asterisk shows approximate Armitage load without temporary transfers to Brown Hill TS

5 EXISTING CONSERVATION AND DEMAND MANAGEMENT

Although there is only a modest impact of CDM in the forecasts, there are a number of conservation and demand management initiatives underway in York Region which will influence the demand for electricity.

5.1 Public Policy and the Demand for Electricity

The growth in the demand for electricity can be analyzed in two ways, a top down, or macroeconomic approach, or in a bottom-up, end-use manner, looking at the individual ways that electricity is used. In the macro approach, the demand for electricity is seen to grow as the economy grows. A smart forecast will recognize that the different sectors of the economy are growing differently, and that different sectors of the economy use electricity differently, and with different intensity. Government policy with respect to interest rates, taxation, etc, can be seen as influencing economic activity, and hence the demand for electricity.

The demand for electricity can also be approached in a bottom up or end use manner. This considers, for example, the number of appliances and their typical use. The total demand is the aggregate over all technologies. However the efficiency of appliances that use electricity, and the way that we use them is also subject to government policy, regulation and influence. Building codes and appliance efficiency standards for example have been steadily improving the efficiency of use. Public education programs influence use patterns and increase awareness of alternative technologies. While the federal government can be thought of as the major player affecting overall economic activity, Federal, provincial and municipal governments all influence efficiency standards. The impact of all these programs and initiatives is to reduce the demand from what it would otherwise be.

The electricity distribution companies can also, within the framework set out by the provincial government, spend moneys and run programs to further reduce the demand for electricity.

These three levels of impact are shown diagrammatically in Figure 5.1. It should be noted that this is simplified picture and that many grey areas exist. For example municipal governments may promote participation in Federal programs, and the Ontario Government has instructed the province’s electric distribution companies to make efforts to reduce their peak demands and to install ‘smart’ meters.

The following sections describe some of the activities and programs that are currently underway to influence the demand for electricity. They are approached in the order outlined above. Federal and Provincial initiatives to improve efficiency of use are described first, and then specific utility delivered programs are covered in the following section.

5.2 Some Federal, Provincial, Local and Other Initiatives

Federal initiatives these days are largely driven by the need to met Canada’s Kyoto commitments, and their programs, such, as the One-Tonne Challenge are thus primarily aimed at reducing atmospheric emissions through conservation measures. Most of the programs are run by the Office of Energy Efficiency (OEE) that is part of Natural Resources Canada. They are organized on a sector basis, and some of their programs in the residential, commercial and industrial sectors are described below. Further details can be found on the NRC web site at: NRC Portal. In the residential sector there is a wide range of programs including Energuide for Houses, Appliances, and Heating and Cooling equipment, EnergyStar, R-2000, and the One-Tonne Challenge. The chief offering in the commercial sector is the Model National Energy Code of Canada for Buildings 1997 (MNECB). This contains cost-effective minimum requirements for energy efficiency in new buildings. Natural Resources Canada has programs for the industrial sector in the following areas, financial assistance, technical information, regulations and standards, leadership and networking opportunities, and training and awareness.

Ontario's programs, while having an environmental underpinning, seem to be largely driven by the looming shortfall in electricity capacity. The Province is in the initial phase of its declared aim of moving towards a Culture of Conservation, as well as setting up some of the institutional framework, and has moved to improve efficiency standards. These code changes will have to be factored into any new load forecast.

The Provincial government has also given the electric distribution companies money for conservation and demand management programs. This initiative is described in the following section.

Other bodies encouraging conservation in Ontario or across Canada include:

- the Toronto Region Conservation Authority (TRCA),
- the Federation of Canadian Municipalities (FCM), and
- The Canada Green Building Council (CGBC).
- The Natural Gas companies (Union and Enbridge) also deliver conservation programs to their customers. More details of these activities can be found the Enbridge website.

While there are a lot of programs out there, they are generally information programs. Where financial incentives are offered, they are generally a "drop in the bucket", i.e. very small compared to the cost of projects.

5.3 Distribution Company Programs

After the de-regulation of the electricity sector in the mid 1990s, neither the distribution, transmission or generation companies had a mandate to pursue Conservation and Demand Management (CDM) activities. With the recent tightening in the supply position, the Ontario Minister of Energy has called for the creation of a "Conservation Culture" in the province. He has established two objectives for the electricity sector and electricity customers. First, he has targeted a reduction in Ontario's peak demand for electricity of 5% by 2007. Given that overall load growth in the province was forecast to be about 1% , if successful this will effectively mean that there is no or negative growth in peak demand over the period. Second, he has committed to the installation of 800,000 SMART electricity meters by 2007, and the full deployment of SMART meters for all electricity consumers by 2010. To finance the distribution companies CDM efforts, the Minister tied an increase in allowable return, to investment in CDM initiatives. The Minister also encouraged partnerships with government bodies and other agencies, such as Natural Resources Canada and the Canadian Federation of Municipalities, and with local community-based conservation agencies and authorities, some of which were described in the previous section.

In October 2004, the Ontario Energy Board (OEB) issued a procedural order that addresses applications for CDM plan approval, and, since then, has approved the plans of all four utilities in the York Region. These plans are summarized and analyzed below.

With regard to SMART meters, the OEB submitted its implementation plan to the Minister on January 26, 2005. The proposed plan identifies the mandatory technical requirements for smart meters and the support systems distributors will require; sets priorities for implementation in order to meet the government's targets; identifies regulatory mechanisms for the recovery of costs; and identifies how barriers can be overcome. In addition, the report addresses competitiveness in the provision and support of smart meters and the need for and effectiveness of non-commodity time of use rates. The Board's plan is to encourage large distributors to carry out an initial set of pilot programs using dedicated conservation and demand-management funds during 2005 to gain useful information about the installation and operation of smart meter systems before making final decisions on the particular system that they intend to choose. The Board expects distributors who have held pilot projects to share lessons learned with other distributors.

The OEB also called on the Independent Electricity System operator (IESO) to identify constrained areas for priority installation of smart meters. The OEB's plan proposes that the costs be included in the distribution rates as soon as a distributor starts to install smart meters.

The activities of the four York Region Distribution companies are summarized below. The material is taken from the plans submitted to the OEB by the distribution companies. The OEB's summary of the plans, and their decision and orders governing the plans can be found on the OEB website, the plans themselves can be found on the individual utility websites. Understanding of the both the CDM and Smart meter programs was supplemented with conversations with PowerStream, Hydro One, and Newmarket Hydro.

Table 5.1 allows comparison of the activities of the distribution companies in the Residential and Small Commercial sectors, and Table 5.2 addresses the Commercial, Industrial and Institutional sectors. In some cases the companies programs cover multiple sectors, in which case it has been entered in both tables.

- When reading the material below it should be borne in mind that that the supply problem is essentially a summer peak problem, and so programs are needed that address summer loads, air-conditioning loads, and price responsive programs (based on smart meters) for example.
- Given the sensitivity of load to extreme weather, and the fact that this is when problems are most likely to appear, the program design and assessment must be such as to recognize the natural desire to circumvent control measures in extreme conditions.

Some of the utilities initiatives have been characterized as pilots. This means that initial spending will be made to resolve issues in program technology, delivery channels, etc. In most cases the budget includes monies for a full-scale follow-up. However, these programs should be considered as more problematic, and more likely to have a delay before they have significant penetration.

Based on 2001 and 2002 actual loads, the proportion of loads of Armitage going to Aurora, Newmarket and Hydro One are around 23%, 37% and 40%, respectively. Each utility is also expected to contribute to the growth in demand. Therefore the programs of all three of these companies are of significance.

Newmarket, has not, like the other utilities, identified a full range if independent programs. Rather it has a partnerships with Ecosystem and Homeworks for the delivery of comprehensive energy management solutions. Thus while compared to the other utilities, Newmarket seems to be light on Demand Management programs, and programs in the Commercial and Industrial sectors, the partnership with Ecosystem is capable of delivering many different types of energy efficiency and management solutions, and of leveraging the energy programs of others, e.g. Enbridge and NRC.

All the companies also have initiatives to reduce losses in their systems, these initiatives are listed in Table 5.3.

Table 5.4 shows the amounts the companies are planning to spend over the period 2004 – 2007 by program type. It includes both capital and operation expenditures. The company's plans usually include more details.

Looking at the spending per total load, Newmarket, Aurora and Hydro One are spending very comparable amounts. PowerStream's spending is low in comparison with the other three. In absolute terms the amounts the distribution companies have to use, to get 5% reduction in peak demand, seem very low.

Figure 5.2 allows comparison of the percentages being spent in the different program areas. In this chart, spending on smart meters has been excluded. Also the program and administration costs have been shared pro rata across the programs. Hydro One's spending has been redirected in line with the OEB's direction.

Newmarket does not split its budget between conservation and demand management activities. In fact the split will be customer driven, depending on the opportunities that are identified through the audit process. For the purposes of this chart, a 50:50 split has been assumed.

Aurora seems to be spending way more on its Distribution network than the other utilities. Table 5.5 and Figure 5.3 show the spending of the utilities by consumption sector. In Newmarket, a significant portion of residential housing is electrically heated, which explains why the utility spends more than its neighbouring utilities in this sector.

5.4 Conclusions

- PowerStream appears to have a comprehensive set of initiatives and, and is working appropriately with other agencies in the region to maximize its effectiveness, despite spending less per unit of load than the other utilities.
- Aurora has a reasonable set of programs, given its comparatively small size, although much of its spending is focused on cutting system losses. When the merger with PowerStream goes ahead, then the broad based programs and approach being instituted by PowerStream can only work to further improve the effectiveness of the CDM efforts in Aurora.
- Hydro One has a reasonable range of programs; however they all in very early stages of development, and few details are available, except in the area of loss reduction. Partnerships and working with others, while appearing in their general strategy statement, do not appear to feature highly in their plans. Given the broad geographical nature of its service territory, its impact on the loads served by Armitage TS and Brown Hill TS is likely hard to assess. However they have chosen Newmarket as one of the communities to pilot their residential load control project. This project will run from July 2004 to Sept 2005. The pilot is testing the technology, take-up rates and load control actually achieved. The technology appears to be working and refusal rates were low. The lack of very hot days in summer of 2004 means that there are no indications yet as to the effectiveness in controlling load.
- Another point about Hydro One is that they have relatively heavy conservation component. This means that demand management opportunities aimed at summer peaks might still be available.
- Newmarket's approach of partnering with two major Energy Service Companies, should give it maximum bang for their buck. Specific programs in play else where that might be appropriate in Newmarket include:
    - Air Conditioning focused programs for both residential and the commercial/industrial sectors

- A broader community based approach to influencing standards, codes and plans, to encourage sustainable building practices. (as per PowerStream)
- With respect to all the companies it has to be noted that they

- are all effectively starting from scratch;
- have very limited funds;
- have a very limited time to deliver results. Effectively they have to design programs, test and deliver them and get results in a 2-year window; and,
- have no guaranties of future funding at this time.

In light of this it will be very difficult to reach the 5% target reduction in 2007.

Table 5.1 - Residential and Small Commercial Programs

Program Type	**PowerStream**	**Aurora**	**Newmarket**	**Hydro One**
Co-branded mass market program (education and promotion	Program	Program	Program	Program
Smart meter	Pilot	Pilot	Program	Program
Interval Metering				Pilot
Design advisory/audits/retrofits	Program		Program (Homeworks)	
Load control	Program		Pilot (Gateway-complete)	Program
Social/low income housing	Program	Program	Program	Program
AC upgrade		Pilot		
Residential real time monitoring				Program

Table 5.2 - Commercial, Industrial and Institutional Programs

Program Type	PowerStream	Aurora	Newmarket	Hydro One
SMART meters	Program		Program[2]	Program
Interval Metering				Pilot
Time-of-Use				Pilot
Energy audits, retrofits and partnerships	Program		Program [3](Ecosystem[4])	
Leveraging conservation and LM programs	Program			
Demand response	Program			
Design advisory	Program	Program		
Big Box retailer retrofit		Pilot		
AC conditioner upgrade		Pilot		
Manufacturing energy upgrade		Pilot		
Power factor corrections		Program		
Institutional		Program (buildings)	Programs (schools & street lighting)	
Festive lights		Pilot		
Load Control/Management			Program (Ecosystem)	Program
Farm Energy efficiency				Program
Distributed Energy	Program			
Standby Generators	Pilot			

[2] While not described in Newmarket Hydro's published plan, the company does in fact have a program of installing meters in Commercial and Industrial premises. Currently the focus is on customers with loads greater than 500 kW. In addition, as part of the Ecosystem Audits, at each audit site a meter is installed, if it not there already.

[3] Being a general audit, and energy service company Ecosystem is capable of recommending and implementing a range of efficiency and demand management techniques. Hence the program fits in a number of categories. Probably more than have been identified.

[4] Ecosystem is an independent Energy Services company. It is the largest energy efficiency contractor in Quebec.

Table 5.3 - Distribution Network Loss Reduction

Program type	PowerStream	Aurora	Newmarket	Hydro One
Feeder Phase balancing	Program			Program
Power Factor correction	Program			Program
Others	Program	Pilot (loss reduction)	Program (revised equipment specs)	Program

Table 5.4 - Funding $M by Program Area

Program	Power Stream	Aurora	Newmarket	Hydro One (Before board redirect)
Smart Metering	1.2	0.115	Not included	14.9[5]
Load management	0.7	0.040	[6]	8.7
Conservation	2.7	0.200	0.98	9.2
Distribution Network	0.48	0.350	0.03	2.0
Dist energy	0.64	0	0.00	0.0
Communication/education	0.64	0.037	0.05	1.0
Program Management and research	Inc above	0.075	.0.22	3.7
Total $M (2004-07)	6.4	0.82	1.27	39.5
MW	1300	72	142	3300
$/kW peak demand	4.89	11.347	9.01	11.97

[5] These monies will be redirected to C/I conservation programs, including reduction of line losses (Private conversation)
[6] Not separately identified, included in the conservation programs.

Table 5.5 – Spending by Sector ($M)

	Power Stream	Aurora	Newmarket	Hydro One (Before board redirect)
Residential & small commercial	2.60	0.162	0.69	20.2[7]
Commercial/ Industrial	2.69	0.121	0.28	11.2[8]
Public Infrastructure	0.0[9]	0.075	0.0	0
Education and promotion	0.0	.037	0.05[10]	1.0
Distribution Network	0.48	0.35	0.03	2.0
Distributed Energy	0.64	0.0	0.0	0.0
Program Admin	Inc. above	0.075	0.22	5.1
Total	6.41	0.82	1.27	39.5

[7] Redirection will reduce this by approx 7.2 M
[8] Redirection will increase this by approx 7.2 M
[9] Included in C/I above
[10] In addition to these funds, Newmarket Hydro will be spending $20 k to start the development of a Social Housing education package. They will also be providing $50 k in funding to environmental education organization.(Earth Rangers)

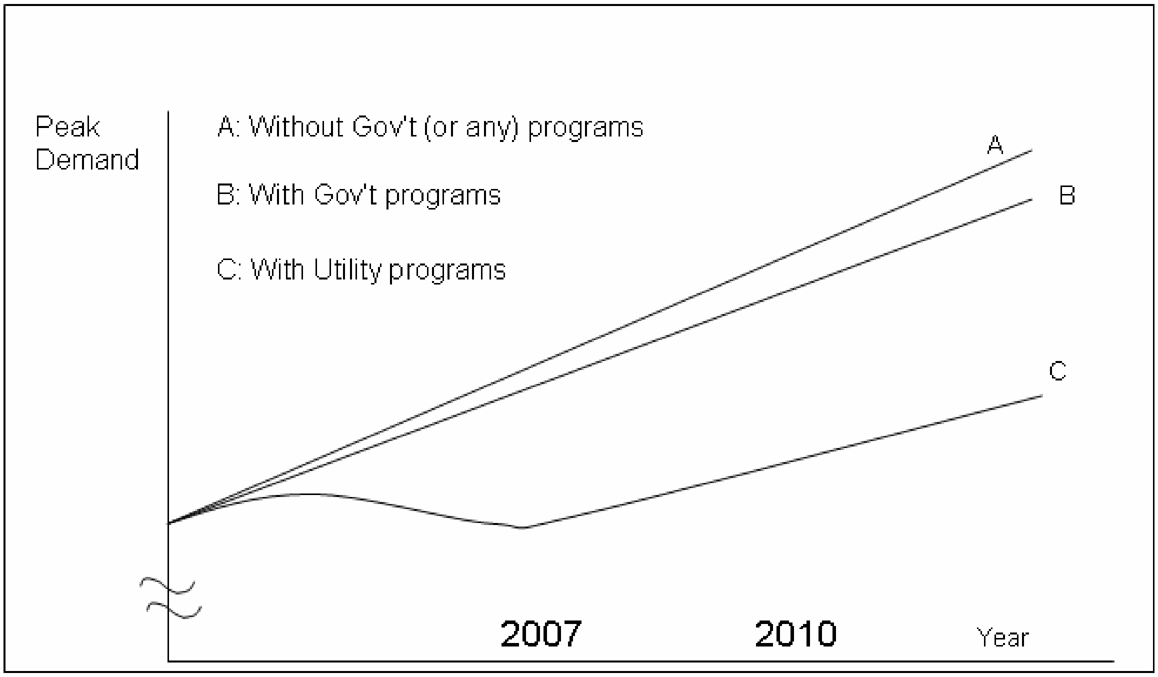


Figure 5.1 – Program Impacts on Load Forecast

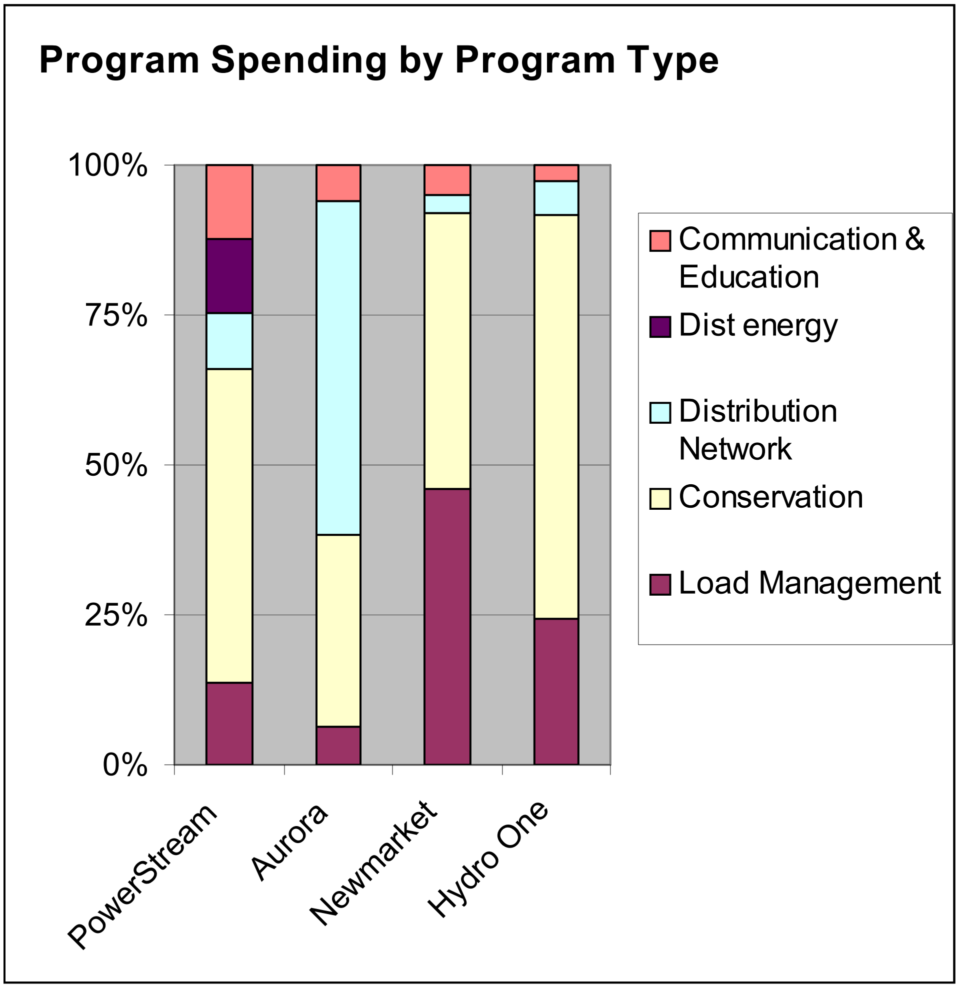


Figure 5.2 – Spending by Program Type

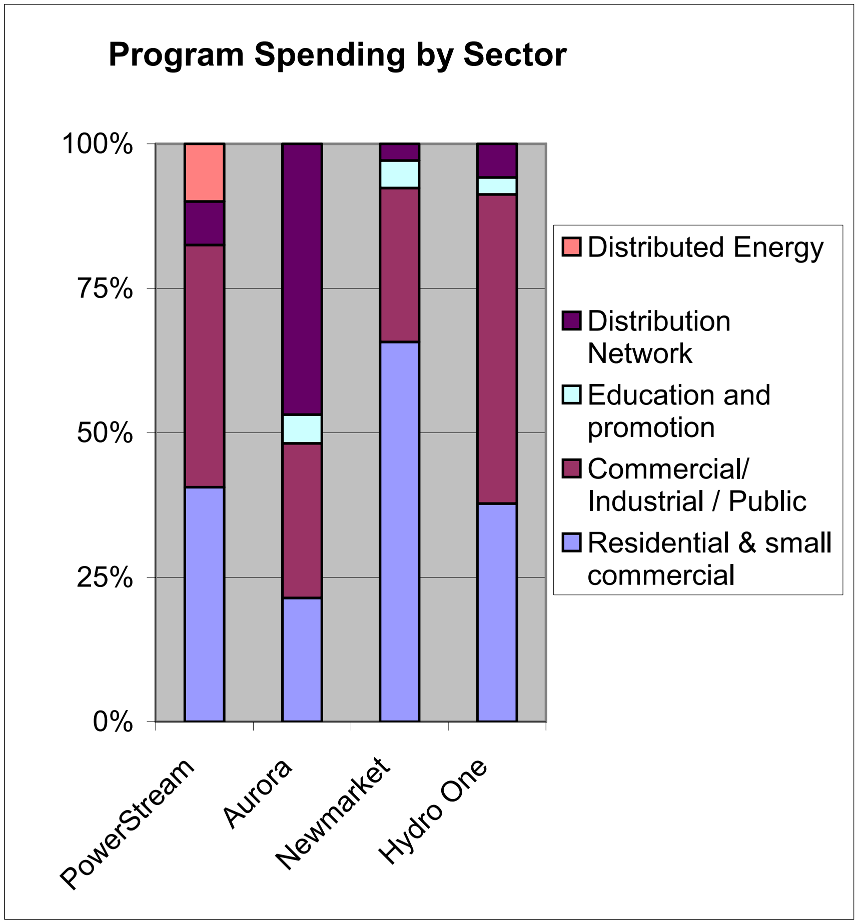


Figure 5.3 – Spending by Sector

6 FUTURE CDM INITIATIVES

6.1 Current CDM Focus

The Minister of Energy has established an objective for a 5 percent reduction in Ontario's peak demand by 2007. Given that overall load growth in the province was forecast to be about 1% , if successful this will effectively mean that the 2007 peak will be equal to the peak of 2002. A companion program to the reduction objective was the installation of 800,000 smart meters by December 2007, and to all customers by 2010. To finance these CDM efforts, the Minister tied an increase in the allowable rate of return to the distribution companies, to an equivalent investment in CDM initiatives.

The following categories of CDM initiative are eligible under this program:

- energy efficiency;
- behavioural and operational changes, including application of benchmarking or "smart" control systems;
- Load management measures which facilitate interruptible and dispatchable loads, dual fuel applications, thermal storage, and demand response;
- Measures to encourage fuel switching which reduces the total system energy for a given end-use;
- Programs and initiatives targeted to low income and other hard to reach consumers; and
- Distributed energy options behind a customer's meter such as tri-generation, co-generation, ground source heat pumps, solar wind, and biomass systems.

There are a number of CDM initiatives currently in pilot or program status within York Region. A total of $8.5 million has been allocated by the three local utilities. In addition, a portion of the Hydro One provincial CDM allocation of $39.5 million is also directed to programs in York. The Ontario Energy Board has approved the plans of all four utilities in the York Region. Most of these initiatives are financed through the third installment of the incremental market adjusted revenue requirement (the 3rd tranche). There are, however, no guarantees that the CDM initiatives will achieve the 5 percent target nor that the CDM savings will be distributed evenly over the Region. Focused load growth in one area may mask any CDM benefits.

6.2 Need for OPA Involvement

Beyond the monies allocated from the 3rd tranche there is no clear source of funds available to the LDCs in place for CDM. There are basically two elements to a CDM initiative.

- Demand Management would typically shift load from the peak hours to off-peak hours. This reduces the absolute peak that a utility must purchase (or generate), transmit, transform and distribute. A demand shift would not typically affect the amount of energy sold by the utility and therefore would not decrease revenue. It would, however, reduce the stress on the electrical equipment and defer the need for system expansion.

- Conservation would also typically reduce the absolute peak but as it is a less time specific concept, conservation is just as likely to reduce demand at all time periods. This would affect the amount of energy sold and therefore would be expected to decrease revenues.

There is no incentive for an LDC to directly fund a CDM initiative, an investment which could actually decrease its future revenue stream. Figure 6.1 presents a typical daily load curve and illustrates the impacts of both conservation and demand management on the base curve.

By providing customers with more detailed and timely information on their energy consumption, the installation of smart meters is expected to reduce both peak demand and overall energy consumption. The purpose of the meter is to incent customers to move consumption from the peak hours when electricity is expensive to off-peak when it is less costly. The currently approved rates show peak charges as over three times those in off-peak hours. While reductions are expected there are few projections of energy and peak savings. Unfortunately, with the exception of a number of pilot projects, the smart meter program is on hold awaiting a technological selection.

The delay in the smart meter program and the absence of longer term CDM funding for the utilities suggests a province-wide need for some level of intervention by the OPA. The identified bottlenecks in the supply system to York Region presents an opportunity for the OPA to investigate a number of alternative approaches to CDM which may prove applicable to a larger initiative.

To that end, the Ontario Energy Board has directed (July 25, 2005) the Ontario Power Authority to provide both an opinion on the need for new supply in York Region and an opinion on which of four suggested options might be the best way to serve this new demand. The fourth option listed in the Board's request is the supply/demand reduction option. Specifically, this would be "a contract between the OPA and a generator or a consumer for new supply, capacity or demand reduction, the costs of which will be recovered from OPA customers if approved by the Board."[11]

Activities which will be considered include:

- Load control programs through aggregators (Air Conditioner cycling programs)
- Air Conditioner upgrade and appliance exchange programs
- Distributed energy and standby generator programs

6.3 The Request for Expressions of Interest (RFI)

In anticipation of the need for further resources in the Newmarket area, on May 2nd 2005, the OPA issued two Requests for Expressions of Interest, one for Generation Resources, and one for Verifiable Electricity Demand Reduction (DR) in the Northeastern York Region. Figure 6.2 shows the approximate boundaries of the Armitage TS service area within York Region. The RFI for CDM was designed to identify parties capable of providing demand reduction projects, prior to conducting a competitive bidding process. The ultimate bidding process could lead to one or more contracts, subject to the OPA's recommendation to proceed with remedial actions that include demand reduction measures, and approval from the OEB.

The RFI asked for capacity of greater than 1 MW, expecting respondents will aggregate the efforts of multiple electricity consumers. Demand reductions were asked for that would be available during summers and winter peak load periods experienced in the Armitage TS service area. The demand reductions were expected to be verifiable, to be able to respond to price signals or directives from the Independent Electricity System Operator (IESO). The respondents were cautioned that they would be competing with generation and transmission options, and that this might require the program to obtain a significant portion of its revenues from the customers benefiting from the reductions in energy consumption. Payment is anticipated to be based on

[11] - Ontario Energy Board, July 25, 2005, Letter of Direction Re: York Region Supply.

those set out for DR projects in the 2500 MW contract. On-site generation from clean fuels was also eligible.

The OPA has received sufficient interest in the Demand Reduction process in all demand sectors through the RFI to justify a full RFP. The expressions of interest include both demand cycling through aggregators and stand-by or emergency generation. It should be noted that for stand-by generation to contribute to the system the generator must be in full operation *before* the contingency occurs. Once the contingency condition occurs – the lights are out. It is anticipated that the RFP could make available up to 20 MW (in aggregate) of economically viable demand reductions in York Region. Offers in excess of the 20 MW threshold will be evaluated on their individual merits.

6.4 Possible CDM Post 2007

In the longer term there are three things that should be borne in mind in forecasting the level of future CDM activity and hence the load forecast.

Firstly, recently (April 20, 2005) the Minister appointed Mr. Peter Love as Chief Energy Conservation Officer, to head the province's new Conservation Bureau, a division of the Ontario Power Authority. In addition to helping the government meet its target to reduce peak electricity demand in Ontario by five per cent by 2007, the Conservation Bureau will:

- Develop province-wide conservation programs to help consumers save energy and save money
- Promote energy conservation and the efficient use of electricity
- Assess the technical, economic and market potential for conservation in the province
- Report on Ontario's progress in achieving its conservation targets and assess what further action is required.

The OPA has not had time yet to undertake specific CDM initiatives, but its influence is expected to be felt post 2007 and must be factored into long-term load forecasts. In order to effectively deliver CDM, the OPA and the Conservation Bureau, in particular, will require the engagement of local entities; the municipalities, the LDCs. There must also be an effective measurement and monitoring program in place to identify the level of CDM being delivered by each program. The OPA should also consider a mechanism to allocate more funds to programs which show significant achievements.

The second factor is that in its guidelines for the preparation of the 2007 rates cases that the distribution companies must file, the OEB has made it clear that as well as being compensated for the reduced load of such programs, there will be incentives for the shareholders of the companies as well. It must therefore be expected that distribution company activities will continue after 2007, but at what rate is unclear. Many utilities will want to wait and see the details before they start planning longer-term activities. OPA in partnership with LDCs and providing these incentives if necessary would strengthen and coordinate the role of the LDC as the delivery agents for CDM.

And finally, the program to install smart meters, currently scheduled to be complete by 2010, will leave an unprecedented capability for the provinces electricity users and utilities to respond to the pricing signals that will accompany peak demands. This capability to respond to price signals can be expected to have significant impact on the growth in peak demand in the future, but this depends on the tiered pricing being passed on to end-use consumers, and on its continuation into the future. Despite a target of 800,000 Smart Meters by December 2007, with the exception of a small number of pilot projects, the overall program cannot be undertaken pending an decision of the appropriate technology to include in the meters.

Beyond 2007, CDM could include:

- Funding for the ‘better’ CDM programs, particularly those that are focused on Demand Reduction
- An RFP for Demand Reduction in York Region to be used as a template for a Province-wide initiative
- OPA partnering with Government and the Ontario Energy Board for the installation of smart meters.

6.5 Northern York Region – Demand Management Plans

The OPA has set a minimum target of 20MW of demand reduction through Demand Response programs in Northern York Region over the study period. These programs will have an aggressive initial target of at least 10MW to help relieve the loading on Armitage TS in the summer of 2006. With the exception of emergency load transfers, none of the bulk supply, transmission, transformation, or distribution options can be implemented quickly enough to help in resolving the station loading issues. The Demand Response initiative is therefore very important and critical. It will be implemented in part using the RFP process. Programs will be executed by the local LDCs and the private sector. Following this initial effort and for the remaining study period aggressive, economic, Demand Response and other CDM programs will be undertaken. Figure 6.1 below shows the effects of demand reduction by changing the time at which energy is used, and the effects of conservation which reduces consumption of electricity in general.

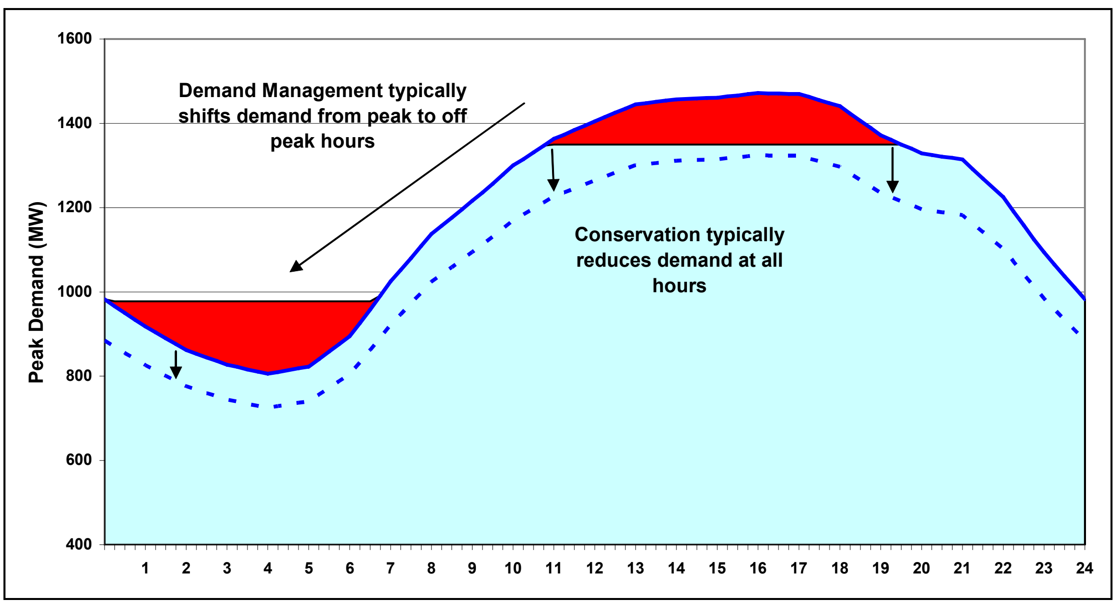


Figure 6.1 – Impacts of CDM on a Daily Load Curve

6.6 Adjusted Load Forecast

The Armitage TS load forecast has been further adjusted to reflect the target of 20 MW demand response (approximately 5%) through the OPA procurement process. This forecast will be used to determine the timing of supply options and is shown by the green dotted line in Figure 6.2 below.

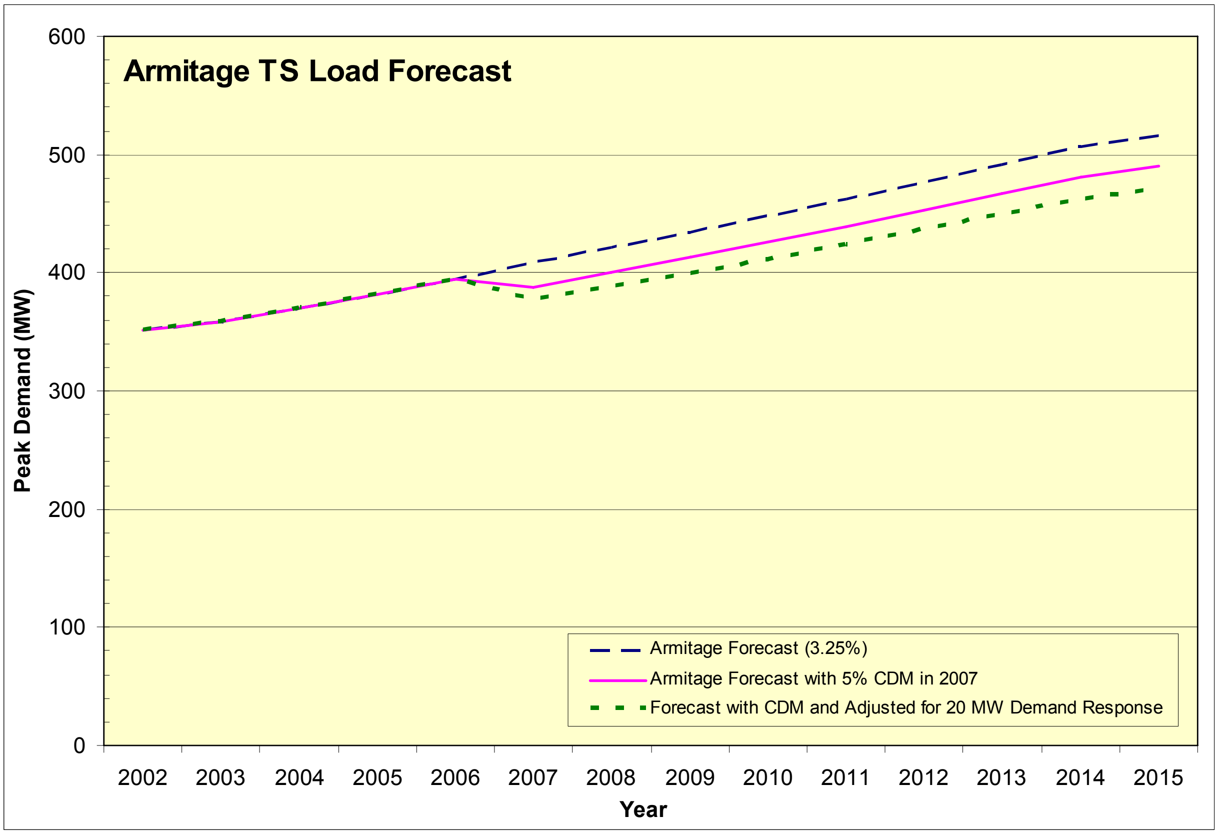


Figure 6.2: Load Forecast at Armitage TS Adjusted for DR Programs

The OPA and affected LDCs will monitor the effectiveness of CDM and DR on a regular basis and revise the load forecast accordingly.

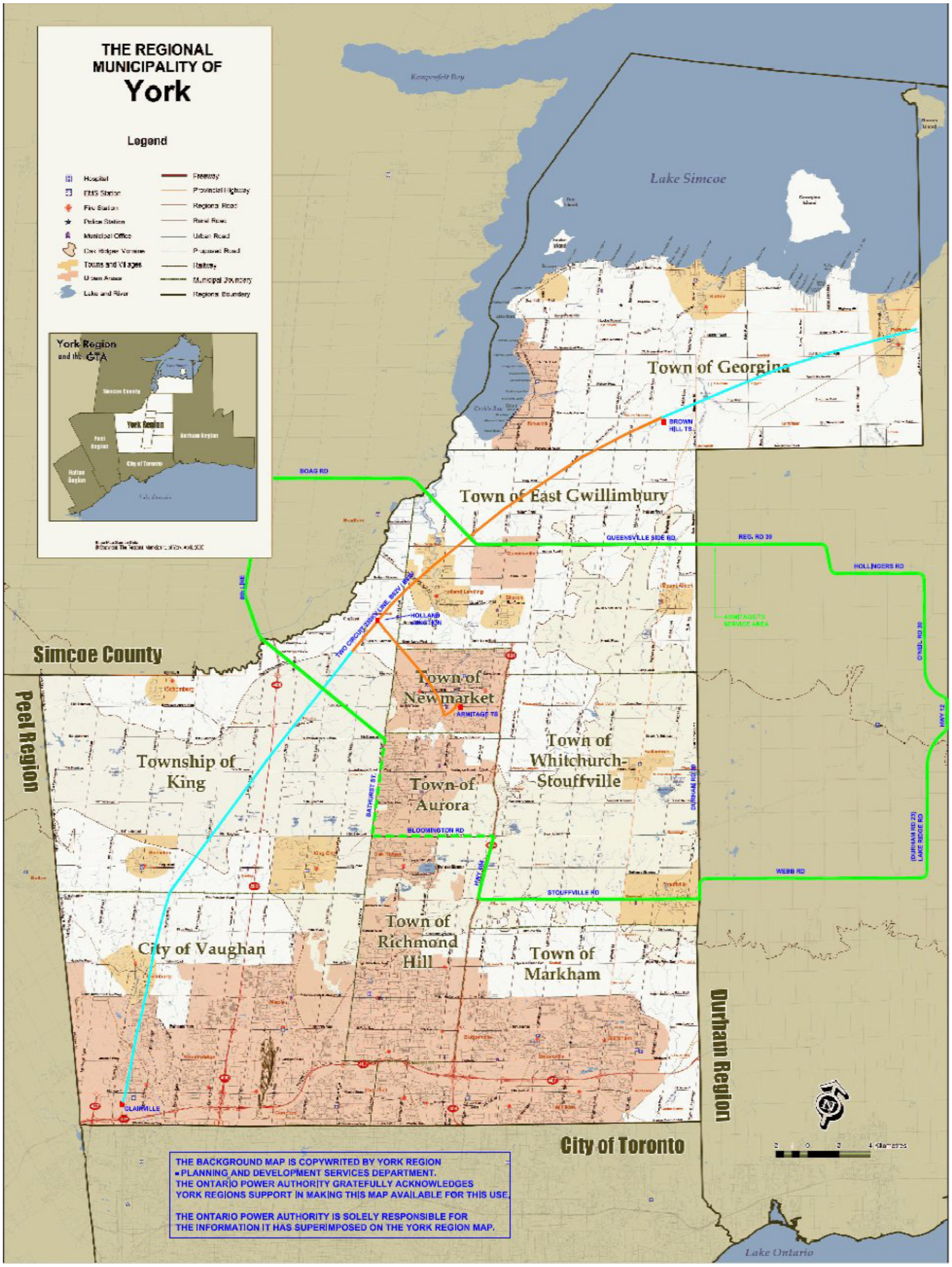


Figure 6.3 – York Region and Approximate Armitage Service Area

Exhibit B - Appendix A

Terms of Reference

TERMS OF REFERENCE
TO REINFORCE THE ELECTRICITY SYSTEM IN YORK REGION, ONTARIO

1. INTRODUCTION

For a variety of reasons that usually result from general economic growth, the bulk electricity supply systems in some areas of Ontario require reinforcement. The required reinforcement can typically be achieved in a number of alternative ways involving such things as new transmission facilities, upgrading existing transmission facilities, new local generation, conservation and load management measures or some combination of these. In some cases, distribution system expansion or reinforcement might also be required either as a standalone solution or in conjunction with other alternatives.

The Ontario Power Authority ("OPA") is currently contracting for consulting services to assess the current and expected service levels in the York region and determine the consequences to consumers if shortcomings are not addressed. The contractor will then develop and analyze alternative solutions and select the most appropriate approach to implementing reinforcement to the existing electricity system in York Region. The selection of Acres International (the "Consultant") to lead this work is in direct response to the company's reply to the OPA's recent Request for Statement of Qualifications.

York Region, one of the fastest growing areas in the province, currently has a combined load of over 1,700 MW. Electric load in the area, as identified by Hydro One in its 10-year Transmission Plan for the Province, will soon exceed the load meeting capability of existing facilities. In its 10-year Transmission Plan, Hydro One identified its plan to construct a new double circuit 230 kV transmission line to Newmarket together with a new transformer station. More recently, the company has submitted an Environmental Study Report based on this plan to the Ministry of Environment.

Hydro One's plan, however, is being met with opposition from affected municipalities and residents, as well as the York Region Catholic School Board. In 2004, York Regional Council passed recommendations requesting that Hydro One reassess its plans and options for expanded power capacity in York Region, and give greater consideration to environmental, social and economic impacts on residential areas.

2. ASSIGNMENT

The Ontario Power Authority is contracting for consulting services to analyze the alternative solutions and select the most appropriate approach to reinforcing the existing electricity system in York Region.

The Consultant will be required to develop and provide forecasts that potentially lead to the conclusion that reinforcements to the existing electricity system are necessary, undertake load flow studies and life-cycle cost/benefit analyses as well as an assessment of the qualitative advantages and disadvantages of different alternatives such as predictability of cost and benefits, flexibility to accommodate future changes, public acceptability, and fit with broader province-wide objectives. The Consultant will be expected to take full advantage of analysis work that has already been completed by others, including the Independent Electricity System

Operator (IESO), transmission companies and local distribution companies and, given this information, the Consultant may be required to complete independent forecasts, studies and analyses or to assess the validity of existing material. Identification of and access to any such forecasts, studies and analyses will be arranged by OPA.

The Consultant will also be responsible for preparing a comprehensive report that outlines the alternatives considered and the rationale behind the recommended approach. Finally, the Consultant may be required to participate in public community meetings to explain and answer questions on such forecasts, studies and analyses and provide expert testimony as part of any approvals process before the Ontario Energy Board (OEB).

3. DELIVERABLES

The specific deliverables are:

(a) Review, assess and reconcile load forecasts already prepared for York Region. Clearly document the assumptions and drivers for the forecast, and indicate the sensitivity to weather conditions (normal or extreme weather). As necessary, prepare additional assessments or scenarios that are relevant to the study.

(b) Document the reliability criteria and targets for York Region against which to assess transmission adequacy. Review and verify the capabilities of existing facilities using available power system studies and analyses in the context of the reliability criteria and targets. Determine the nature and consequence of the issues faced by the York region: (congestion, post-contingency vulnerabilities, voltage decline, threat to firm load supply, etc.). Determine the expected frequency and duration of conditions under which such issues may be triggered and provide an assessment of the risks to customers. Finally, determine how much lead-time is projected before the existing infrastructure fails to meet reliability criteria and targets.

(c) Identify and consider supply and demand-side options and potential modifications to the transmission and distribution systems in order to address any issues identified in (b). Consider stopgap or temporary operating solutions that are acceptable and can potentially extend the lead times for more enduring solutions.

(d) Develop, assess and rank alternatives to address the shortfalls identified in (b). One of the options to be considered should be a simple-cycle gas-fired aero-derivative 200 MW generating station. The costs and impacts will consider the incorporation costs of generation options, including any upgrades necessary to circuit breakers, lines or transformers .The Consultants will qualitatively include environmental and societal impacts in their assessments, as well as operating considerations arising from the option.

(e) Discuss the results developed in (d) with OPA and other stakeholders to obtain their input and comments. Make refinements as necessary and develop recommendations. Participate in public community meetings to explain and answer questions on the recommended alternative.

(f) Provide expert testimony as part of any approvals process before the Ontario Energy Board (OEB).

4. CONTRACT STANDARD

The Consultant will be required to enter into an Agreement with the OPA for the provision of the Deliverables in the attached form.

Exhibit B - Appendix B

marketPOWER research report

Review and Assessment of York Region Load Forecasts and CDM Programs

A reported submitted to Acres International Limited
by
marketPOWER research inc.

Revised … June 19, 2005

Background

The threat of peak load demand exceeding capacity has been identified by the Ontario Power Authority (OPA) as an issue that must be investigated and resolved to the benefit of those residing and working within the York Region. In February of 2005, the OPA contracted with Acres International Limited to investigate several aspects of the potential threat to the York Region service. Acres, in turn, contracted with marketPOWER research inc. for the following services:

Task A from the original contract between Acres International and marketPOWER research:

- "to "Review the existing forecasts", "Analysis and assessment of the existing forecasts" and "Reconciliation and Recommendations" on applicability of current forecasts. Developing new load forecasts was considered to be a "contingency". While we are interested in providing new forecasts, that task goes beyond the estimated costs in Deliverable A in the following table."

Task C from the original OPA contract with Acres International:

- "the reviewing and assessing of current DSM/DRP. The design of new DRP/DSM programs is considered to be a contingency and will be completed as needed. The costs of tat task may exceed those listed under Deliverable C in the following table."

This report is submitted in response to Task A and Task C. Part 2.2 and Appendices B1 and B2 were written primarily by Michael Agrell.

If Acres International Limited or the Ontario Power Authority decides to publish or release information from this report in an edited, truncated or revised version, marketPOWER research inc. will be given the opportunity to disassociate itself from the publications or release of information by asking not to be acknowledged.

Executive Summary

1. The existing load forecasts, conducted by the IESO, Hydro One Networks, PowerStream, Aurora Hydro and Newmarket Hydro, were evaluated in detail. Our main findings are:

    a. None of the forecasts has come to grips with the role that electricity prices may play in determining the demand for electricity.

    b. CDM has not been adequately accounted for in the forecasts.

    c. The sensitivity of peak demand to variation in weather has not been adequately addressed in the forecasts.

    d. Because there is no independent forecast of the Hydro One service territory, there is no basis for substantiating the forecast for the Hydro One service territory. Therefore, the load forecast for the Hydro One service territory is incomplete.

    e. There are inconsistencies in methodologies and assumptions across the forecasts of the different utilities.

    We therefore make the following recommendations in regard to the load forecasting of utilities operating in York Region:

    i. Electricity prices and their future rate structures should be accounted for in forecasting.

    ii. Forecasts at the regional level should be consistent with province-wide forecasts.

    iii. An independent load forecast for Hydro One's service territory should be provided.

    iv. In the future, impacts of CDM programs should be incorporated into load forecasts.

    v. The variability around the base demand component, mostly attributable to weather, needs to be quantified in forecasts for York Region for both the winter and summer peaks.

    vi. New independent peak demand forecasts addressing recommendations i. to v. should be constructed for York Region, with particular attention to the transmission stations (including Armitage) in the northern part of the region.

2. CDM programs, both conservation and demand response programs, were identified and assessed.

    a. Working within an approval process determined by the Ontario Energy Board (OEB), the LDCs operating in York Region have developed a menu of conservation programs, which are now being undertaken.

        i. These programs appear to draw effectively upon the experience of energy utilities in other jurisdictions and there are good reasons to expect tangible results from them.

        ii. However, the present programs – to be pursued over the next two years – should be viewed only as a first step in exploiting the potential of the LDCs' involvement in reducing electricity demand through energy efficiency measures. Fuller realization of this potential will require clear policy directives and leadership from the Government and Ontario's Conservation Bureau.

        iii. Because the levels of expenditures applied to these programs have not been determined by targeted amounts of demand reduction, and the LDCs have not provided estimates of the impacts of their individual programs, a forecast of the overall impact of the LDC programs would be difficult and costly to prepare and has not been attempted in this report. However, data on KWHs saved through conservation programs will gradually become available as LDCs submit the quarterly and annual reports on their CDM activities required by the OEB.

        iv. Conservation programs have variable impacts according to the types of change targeted and the nature of the incentives; for example, shifting customers off of electric space heating can bring large returns. For this reason, we recommend a study of load characteristics in the areas of York Region most in need of capacity increases with a view to identifying specific 'high-yield options' for conservation programs.

    b. LDCs in York Region have not drawn upon much of the potential offered by demand response programs.

        i. Demand response programs can substantially reduce peak load demand during critical periods and can lead to longer term behavioral changes. Evaluations of existing DRPs in other jurisdictions, primarily in New York State, indicate that they work well if they are properly designed and marketed.

ii. We recommend research into the application of short term and long term demand response programs in York Region and elsewhere in the province.

iii. We recommend that a portfolio of pricing products should be researched for development in York Region to encourage load shifting and conservation and so that the potential of installed Smart Meters can be realized.

Part 1: Evaluation of Existing York Region Load Forecasts

1.1 Overview

The purpose of Part 1 is to review and assess the existing load forecasts of peak demand pertaining to York Region. We have not attempted, nor have we been commissioned, to provide an independent load forecast.

While the immediate concern may be with demand meeting capacity through the 230kV line to Armitage and Brown Hill, supplying Hydro One, Newmarket and Aurora, this evaluation provides a complete picture of the load forecasts pertaining to all of York Region.

In conducting our review, we appreciate the documents provided by Aurora Hydro, Newmarket Hydro, PowerStream, Hydro One, and the Independent Electricity System Operator (IESO). Without the cooperation of these organizations, this review and assessment would not have been possible.

We consider a number of key elements in our assessment. Among them are statistical methodology, reasonableness of the underlying forecasting model, input assumptions, treatment of weather, allowance for potential future conservation and demand management (CDM) programs, and extent of geographic coverage.

We have attempted to be concise. Critical comments are provided, but we recognize the earnest effort expended in assembling the forecasts.

We begin with providing an assessment of each of the five forecasts. This is followed by a summary of the treatments of CDM and weather sensitivity. We conclude with an overall assessment, including reconciliations where possible and six recommendations.

The conclusions of our assessment can be summarized as follows:

a. Because there is no independent forecast of the Hydro One service territory, there is no basis for substantiating the forecast for the Hydro One service territory. Therefore, the load forecast for the Hydro One service territory is incomplete.

b. The sensitivity of peak demand to variation in weather has not been adequately addressed in the forecasts.

c. None of the forecasts has come to grips with the role that electricity prices may play.

d. There are inconsistencies in methodology and assumptions across forecasts.

e. CDM has not been adequately accounted for in the forecasts.

In light of the above, new independent peak demand forecasts should be constructed for York Region.

1.2. Evaluation of Existing Forecasts

1.2.1 Approaches to Load Forecasting

There is a variety of approaches and methods for medium- and long-term forecasting. Some approaches are end-use based, some are econometric and statistical, and some are combinations of both approaches.

Our focus in this report is on assessing the forecasting of peak demands over a period of ten to twenty years. A wide range of factors contribute to the long-run growth and variation of electricity demand over a period of such length.

From an economic and demographic perspective, increases in population, number of households, employment and Gross Domestic Product (GDP) all contribute positively to growth in demand.

Electricity prices and other fuel prices also influence demand. Overall increases in electricity prices relative to some appropriate general price index (consumer price index, producer price index) tend to reduce demand and encourage conservation. Overall increases in electricity prices relative to other fuels, and the escalation of other fuel prices (oil, natural gas) tend also to influence demand. New rate structures (block structures, time-of-use prices, revision of demand charges) will have an influence too.

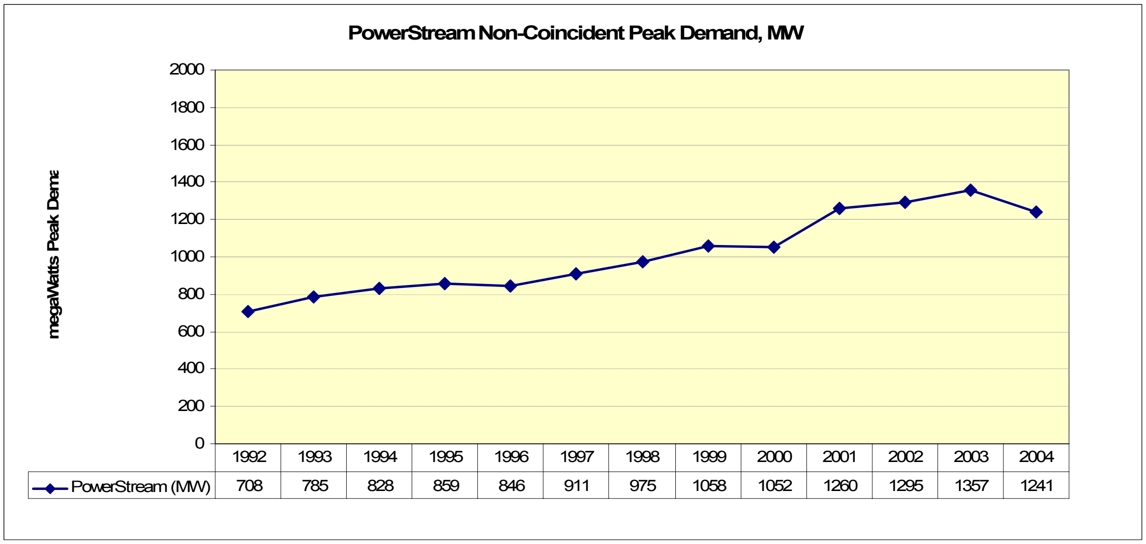
Variation in weather is a major source of variation in peak demand from year to year. Unusually hot summers can result in large increases in summer demand; unusually cold winters can result in large increases in winter demand. This valuation should be quantified, since an electric utility must be able to meet peak demand on an extreme weather day, however this is defined.

1.2.2 Existing Forecasts

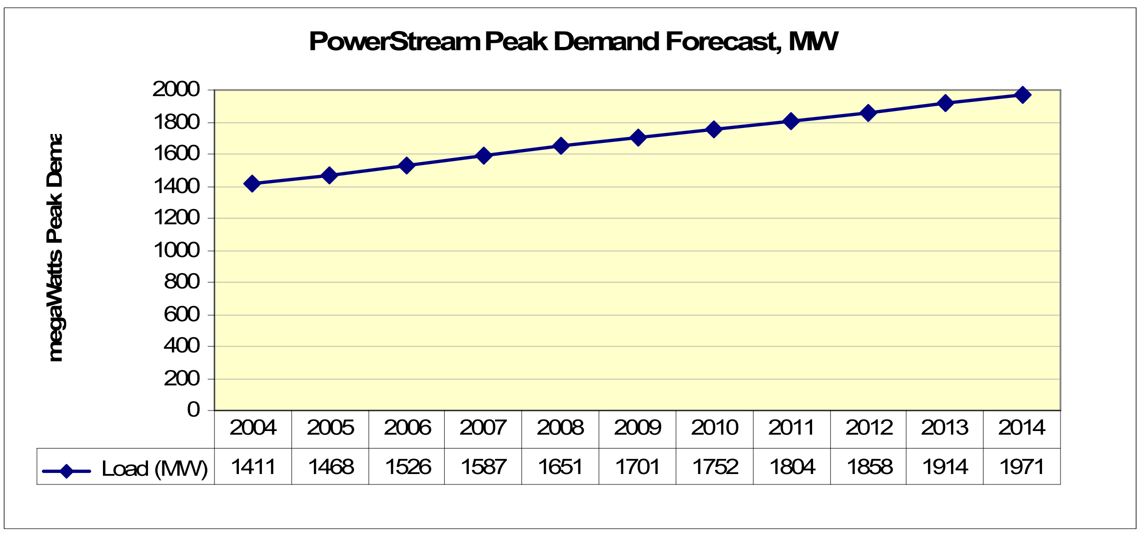
For each of the five forecasts pertaining to York Region, we begin by presenting the historical growth in peak demand. This is followed with a presentation of the particular recommended forecast by the utility or agency under examination. However, it should be noted that this presentation does not constitute an endorsement from our evaluation. We follow with a description of the methods and assumptions used by the utility in creating their forecast. A detailed assessment is then presented. Finally, we summarize and make recommendations regarding key criteria we used on our evaluation.

1.2.2.1 PowerStream:

Historical Growth for PowerStream Peak Demand.



PowerStream's Forecast:



Methods and Assumptions:

PowerStream uses two approaches ("PowerStream Load Forecast 2005-2014", Engineering Planning, March 2005). The first approach starts with projections of population and employment growth, and then translates them into forecasts of additional electricity load. The second approach is based on observed time trends in load. The forecast horizon is 2014.

In the first approach, PowerStream begins with a population forecast provided by Hemson ("Growth Management Update Analysis Report" for Richmond Hill prepared by Hemson Consulting Ltd., May 2003; "The City of Vaughan Development Charges Background Study" prepared by Hemson Consulting Ltd., May 2003; "The Town of Markham Development Charges Background Study" prepared by Hemson Consulting Ltd., May 2003). Appendix A provides a review of the Hemson forecasts. For the PowerStream service territory, which consists of the municipalities of Vaughan, Markham and Richmond Hill, the total population is projected to rise from 522,622 in 2001 to 623,700 in 2006, and then to 811,000 by 2021. This means that between 2005 and 2021 there might be an estimated additional 41,000 housing units in Vaughan, 33,400 in Markham and 24,500 in Richmond Hill. These housing growth figures are multiplied by 3 kW (3.3 kVA) per housing unit.

Corresponding employment projections (also provided by Hemson) from a base of 273,445 in 2001 are 343,510 in 2006 and 473,270 in 2021. These figures are translated into a projected average growth of 551,795 square meters of nonresidential space per year. An assumption of 0.08 kVA per additional square meter is made.

Using the above assumptions, results in an average addition of 66 MVA per year. In fact, a constant additional load of 66 MVA in every year is projected for the period 2005 to 2014. This results in an additional 660 MVA over the ten-year period (see Table 15 of "PowerStream Load Forecast 2005-2014").

In the second approach, PowerStream looks at the growth in the yearly peak between 2003 and 2004. The annual growth rate (after adjustment for weather) turns out to be 4% and this rate is carried through to 2008. From 2009 to 2014 it is reduced to 3% per year. CDM is cited as the reason for the reduction.

In the end, the PowerStream forecast report opts for the trend method because it is more "conservative" and because of "positive historical experience". The PowerStream forecast also provides low and high forecasts (see Appendix C) using +/- half of the base forecast rate. No justification of the high and low growth rates is provided.

Assessment:

1. While the Hemson forecasts provide a basis for the PowerStream calculations, Hemson's higher projected growth rates for population, housing and employment in the first few years do not get reflected in the staging of electricity growth over the 2005-2014 period. The fixed rate of 66 MVA for every year is not consistent with the Hemson forecasts.

2. The adoption of the trend forecast seems arbitrary, particularly since it is based on one year's projected increase (2003 to 2004) of peak demand.

3. The timing of the shift from 4% to 3% growth is arbitrary.

4. Moving from 4% growth down to 3% is justified on the basis of CDM. By 2014, this reduction of 1 percentage point would represent a 4.7% reduction in aggregate load. While this may be attributable to CDM, Hemson's forecast that additional housing will decline from 7120 units per year in 2005 - 2009 to 6120 units per year in 2010 - 2014, would lead one to believe that the reduction in growth rate should be well below 3%.

5. The assumption of 3 kW (diversity corrected) per housing unit seems a reasonable basis for growth forecasting. However, the kVA figure of 0.08 kVA per square meter for non-residential service may be high (see comments on the Aurora Hydro forecasts below). While it may be reasonable for > 50 kW customers, it is probably high for < 50 kW customers. No breakdown of general class (non-residential) composition by size of customer is provided. While these factors (3 kW for residential, 0.08 kVA for non-residential) are used for growth in demand, it would have been helpful to see how well they calibrate existing load. Such a calibration would provide more confidence for their use in growth projections.

6. Sensitivity of load growth to variations in weather has not been taken into account. More generally, the year-to-year fluctuations of peaks are not appropriately allowed for. Unless this is accounted for, the tendency of any forecast based on historical patterns will be to underreport the peak. This is because estimated peaks will tend to be smoothed out using historical projections (either econometric, trend or end-use based).

7. While increases in the real price of electricity may have been small or negative during the last five years, given the current energy situation of Ontario a forecast 10 to 20 years into the future should consider the possibility of growth in the real price, changes in rate structures, and the implications for demand.

8. While it is tempting to say that leaving out CDM and electricity price increases should reduce the forecast below the PowerStream recommended projection, since the trend-based forecast is based on one year's growth, it is not possible to determine whether PowerStream's forecast should be adjusted up or down.

Results and Summary:

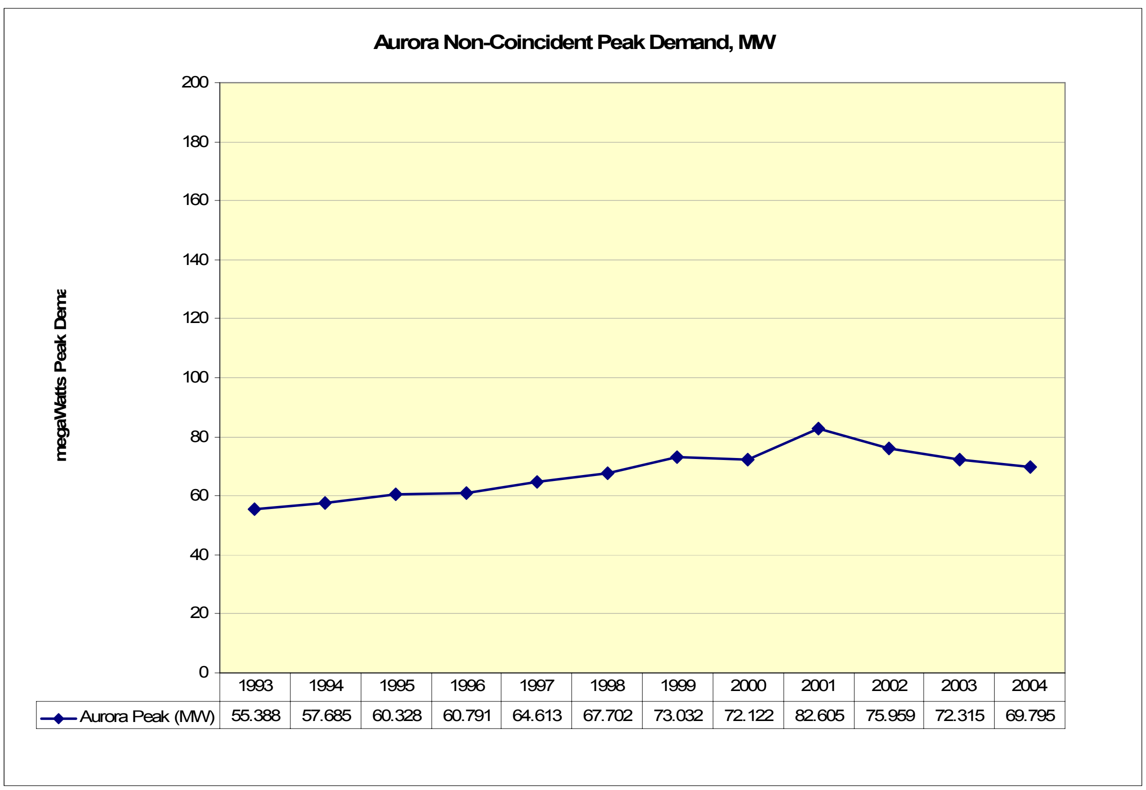
The PowerStream forecast uses a trend-based method for projecting load. The annual forecast growth rate is 3.4% for 2005-2014. The principle concern about this forecast is its arbitrariness; therefore, it is difficult to use this forecast as a reference for further projections.

For the PowerStream forecast, the following table summarizes recommendations pertaining to key evaluation criteria.

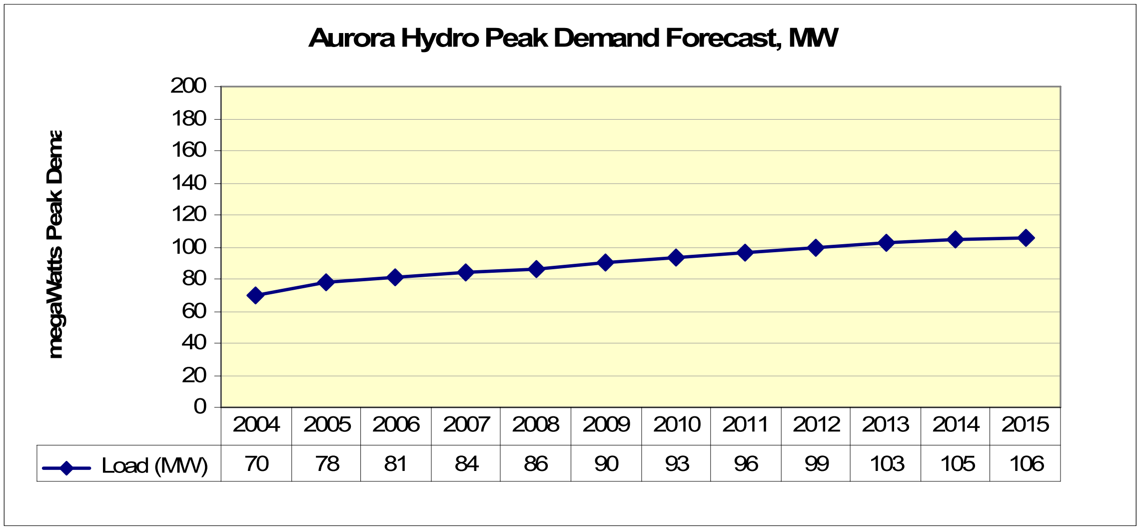
Criterion	Recommendation
Statistical Methodology	Requires further development
Reasonableness of Underlying Model	Requires further development
Input Assumptions	Not applicable/trend-based
Treatment of Weather	Needs to be incorporated
Electricity Prices (with a negative impact on growth)	Needs to be incorporated
CDM (with a negative impact on growth)	Needs to be incorporated
Extent of Geographic Coverage	Satisfactory

1.2.2.2 Aurora Hydro:

Historical Growth for Aurora Peak Demand.



Aurora's Forecast:



Methods and Assumptions:

Aurora uses five methods. The first three are trend-based. The fourth makes use of population/employment projections that eventually translate into forecasts of additional electricity load. The fifth correlates load growth with population growth. The chosen final forecast most resembles the results obtained by the fourth method. The methods are outlined in the document "2004 System Load Forecast" by Irv Klajman of Aurora Hydro. The document provides forecasts to 2028.

Method 1 employs a linear trend technique. Using the annual averages of past monthly system peaks for 1993 to 2004, annual growth of 1.875 MW per year is forecast. The use of annual averages rather than single annual peaks removes seasonality. This method forecasts an additional 1.875 MW per year out to 2028.

Method 2 begins by calculating average historical growth rates of annual peaks. It uses these as the basis for a forecast of 2.3% growth per year up to 2013. On the view that growth will be tempered thereafter, the rate is then reduced to 2.00 % per year until 2028.

Method 3 takes the natural logarithms of the annual peaks and calculates the associated historical growth rates. This results in a forecast rate of growth of 2.68% per year over the whole of the forecast period.

Method 4 is an end-use forecast. Customers are divided into three groups: residential, general service < 50 kW and general service > 50 kW. Residential customers represent 38% of kWh sales, general service < 50 kW customers 9% and general service > 50 kW customers 53%. For industrial and commercial load growth, the key is land development. The forecast of non-residential load relies on square footage forecasts originating with Hemson, and associated kW usage based on a factor of 2.8 W per square foot (0.030 kW per square meter) for < 50 kW customers and 13 W per square foot (0.137 kW per square meter) for > 50 kW customers.

Residential growth is based on a forecast of an additional 2580 housing units over the five-year period 2006 - 2011. This declines to 800 additional units in 2026 - 2031. These housing growth rates are again Hemson forecasts. For translating them into residential peak demand, a factor of 3.5 kW per unit is used between 2004 and 2006, 3.2 kW per unit between 2006 and 2011 and 2.9 kW per unit thereafter

"Natural growth" (for existing customers, that is) is forecast to be 0.75 % per year of the system's maximum summer peak, based on the industrial component of the aggregate load.

Method 5 uses a ratio of kW to population of 1.82 to forecast peak demand until 2028.

The above five methods result in a range of projected demands, from 115 MW (Method 2) to 135 MW (Method 4) by 2028. In the end, the Aurora report provides and recommends a forecast very close to the results of Method 4, the most sophisticated of the five methods.

Assessment:

The following assessment focuses on Method 4, the results of which most closely resemble the recommended forecast.

1. Method 4 is well structured and incorporates considerable detail. Its logic is easily understood.

2. No explicit allowance has been made for CDM. However, in the comparison of Aurora Hydro's 2004 load forecast with the 2003 load forecast, the latest forecast "presumes some impact from Demand Management and Energy Efficiency."

3. The sensitivity of load growth to variations in weather has not been taken into account.

4. No justification is provided for the assumption of "natural growth" of 0.75%.

5. The potential future impact of rising real prices of electricity is not accounted for.

6. The justification for choosing a forecast very close to the results of Method 4 is not provided, although the choice may be a reasonable one.

Results and Summary:

The Aurora forecast uses an end-use method for projecting load. The annual forecast growth rate is 3.2% for 2005-2015. The logic of the Aurora forecast is easily understood.

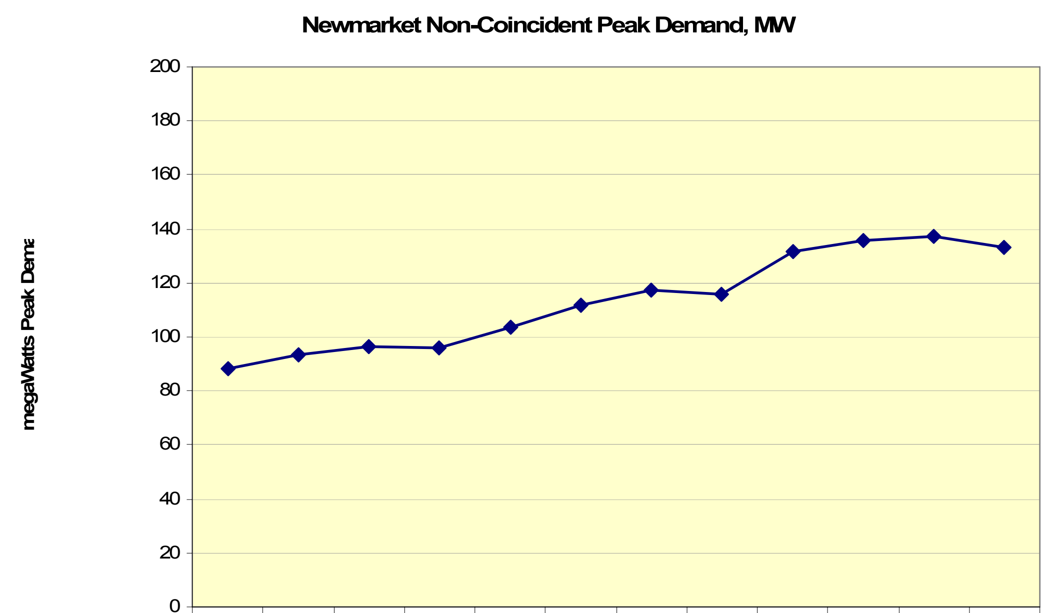
Besides the need to incorporate weather, electricity prices and CDM into their forecast, further development is required on appropriate input assumptions. Further exploration of Aurora's treatment of "natural growth" is warranted.

For the Aurora forecast, the following table summarizes recommendations pertaining to key evaluation criteria.

Criterion	Recommendation
Statistical Methodology	Further development required
Reasonableness of Underlying Model	Satisfactory
Input Assumptions	Some further development required
Treatment of Weather	Needs to be incorporated
Electricity Prices (with a negative impact on growth)	Needs to be incorporated
CDM (with a negative impact on growth)	Further development required
Extent of Geographic Coverage	Satisfactory

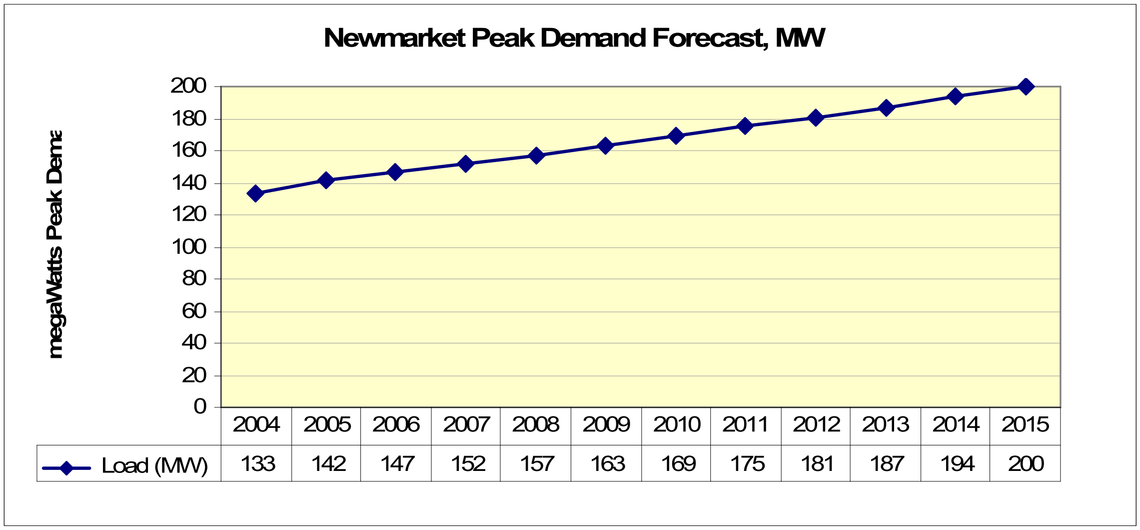
1.2.2.3 Newmarket Hydro:

Historical Growth in Newmarket Peak Demand.



	Sept 93	Jan 94	July 95	Aug 96	July 97	July 98	July 99	Sept 00	Aug 01	July 02	July 03	July 04
NHL Peak (MW)	88.3323	93.3488	96.1762	96.019	103.517	111.679	117.362	115.792	131.727	135.51	137.428	133.011

Newmarket's Forecast:



Methods and Assumptions:

The assessment of the Newmarket forecast is based on projections (by way of tables and supporting background documents) provided to us and subsequent discussions. The forecast horizon is 2028.

The forecast documents explore two methods. The first uses growth rates of population calculated from Hemson population projections. Based on the existing service territory of Newmarket Hydro, it recognizes that the introduction of new geographic areas of service will be severely limited beyond 2015. This is referred to as being "landlocked". The forecast is based on the following annual population growth rates: 4% from 2006 to 2010; 2% from 2011 to 2013; 1% from 2014 to 2028.

Newmarket Hydro's preferred peak demand forecast is a trend forecast that projects a 3.51% annual growth rate from 2006 to 2015. This is based on the observed growth rates from 2001 to 2004, with 2.8% growth per year attributable to an increase in new customer sales and 0.7% to higher sales to existing customers. The annual growth in peak demand is projected to fall to 1% per year in every year of the period 2016 to 2028: 0.5% per year for new customer sales and 0.5%, 0.5% per year for growth of existing customer sales.

Assessment:

1. The forecast does take account of geographic characteristics and restrictions. In consequence, the growth rate declines as the forecast period extends.

2. The trend based forecast, while simple, does not explicitly account for

demographic and employment changes.

3. The potential future impact of rising real prices of electricity is not accounted for.

4. CDM is not accounted for.

5. The sensitivity of load growth to variation in weather is not taken into account.

Results and Summary:

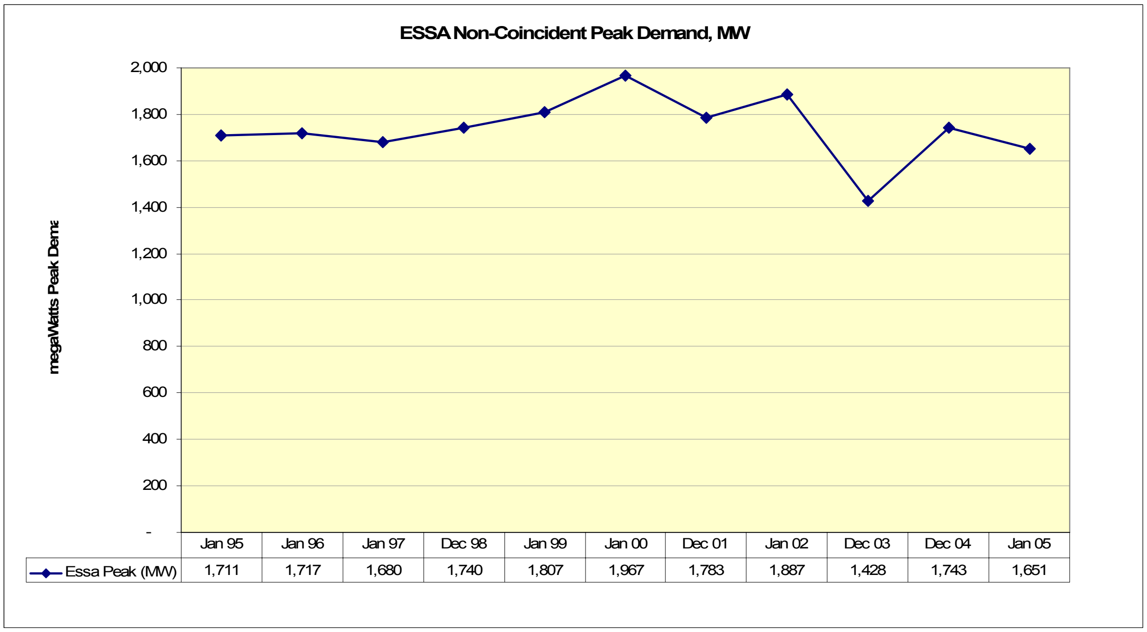
The Newmarket forecast uses a trend-based method for projecting load. The annual forecast growth rate is 3.51% for 2006-2015. The principle concern about this forecast is its arbitrariness; therefore, it is difficult to use this forecast as a reference for further projections.

For the Newmarket forecast, the following table summarizes recommendations pertaining to key evaluation criteria.

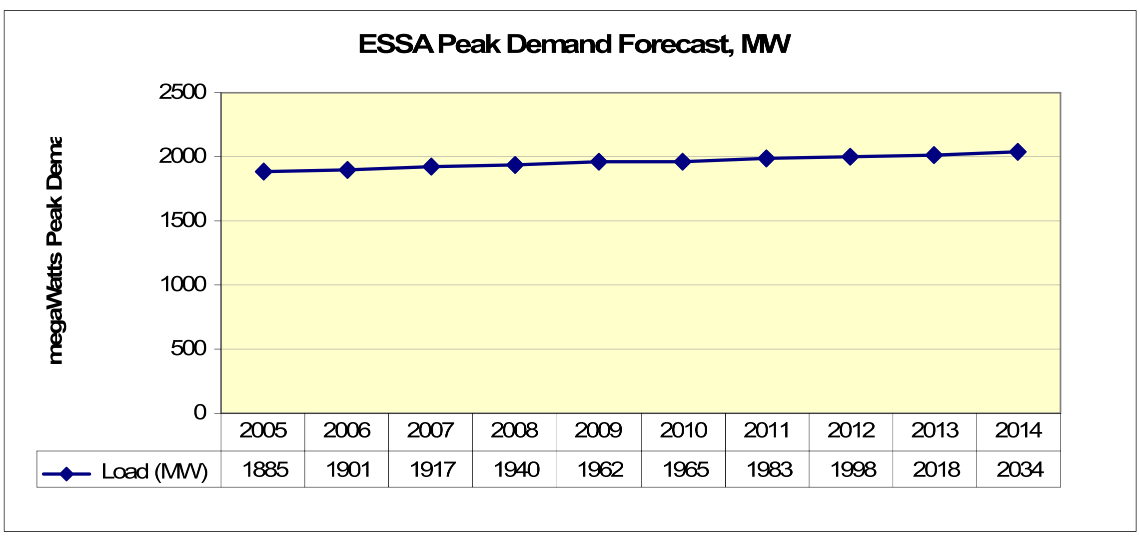
Criterion	Recommendation
Statistical Methodology	Requires further development
Reasonableness of Underlying Model	Requires further development
Input Assumptions	Not applicable/trend-based
Treatment of Weather	Needs to be incorporated
Electricity Prices (with a negative impact on growth)	Needs to be incorporated
CDM (with a negative impact on growth)	Needs to be incorporated
Extent of Geographic Coverage	Satisfactory

1.2.2.4 The Independent Electricity System Operator:

Historical Growth in Essa Peak Demand.



The Independent Electricity System Operator's Forecast:



Methods and Assumptions:

The Independent Electricity System Operator (IESO) makes 18 - month forecasts on a quarterly basis and 10 - year forecasts on an annual basis. For the 10 - year horizon, zone forecasts for Ontario are provided for energy (GWh) and peak demand (MW). The latest 10 – year forecast released is the "10-Year Outlook: Ontario Demand Forecast", March

31, 2004. For our purposes, we focus here on the 10 - year peak demand forecast. In fact, IESO does two types of peak forecasts, by zone: coincident with the Ontario system and non-coincident. Our focus is on zone non-coincident peak demand because this is more closely tied to the regional peaks.

Two of IESO's zones are of interest from the point of view of York region: Essa, which contains the northern part of York, and Toronto, which contains the southern part.

For each zone, the forecasting model is a single equation regression model where the dependent variable is hourly load for each day of the year. The independent variables include weather variables (dry bulb temperature, dew point temperature, wind speed and cloud cover), sunrise and sunset times, calendar variables (day of week, holiday information), employment, number of households, and a trend variable. Historical household data for a zone was constructed using Statistics Canada census subdivision information, and housing starts (for Ontario and relevant Census Metropolitan Areas from Canada Mortgage and Housing Corporation. Statistics Canada employment estimates for relevant economic regions provide the historical data for the zone. The purpose of the trend variable is to capture zone-specific trends such as increased penetration of air conditioning in the summer.

For the first two years of the IESO forecast, employment and household projections are based on Canadian chartered bank economic forecasts. Historical relationships between the banks' projections and zone employment and household variables are developed. For the remaining eight years of the ten-year forecast, the midpoint Statistics Canada population projection (Scenario 3) for Ontario forms the basis for projecting employment and households. Historical relationships between employment, households and population, in conjunction with historical shares of growth in specific zones, lead to projections of households and employment for the zones.

The IESO base forecast assumes "normal weather", as derived from historical data (across 30 years). The daily weather variables are ranked within each week from the historical record and the average for each of the ranked days is calculated. (For example, a median for the coldest day, determined by impact on load, followed by a median for the second coldest, down to a median for the seventh coldest, form the basis for constructing a "normal" week.)

IESO defines two other weather scenarios. An extreme scenario is based on historical weather but uses minima and maxima rather than averages. This technique, accounting for extreme weather, can be used for peak demand forecasts. A second "Load Forecast Uncertainty" scenario is based on one standard deviation of the weather elements. The calculation is in terms of temperature, wind speed or MW contribution, depending on the application. (While these weather scenarios are relevant for peak demand forecasts, the scenarios have no relevance in terms of meaningful extreme week load shapes or kWh projections.)

For the Essa zone, the projected annual growth in winter load (from January, 2005, to January, 2014) is 0.85% per year, and the annual growth in summer load (from July, 2005 to July, 2014) is 0.31% per year. For the Toronto zone the projected annual growth in winter load (from January, 2005, to January, 2014) is 0.73% per year, and the annual growth in summer load (from July, 2005, to July, 2014) is 1.28% per year. These forecasts can be found in Table B2 of "10-Year Outlook: Ontario Demand Forecast", March 31, 2004.

Using the IESO model, the forecaster is able to quantify the impact of variation in weather on the total load. For example, in Table C1 calculations are provided for the megawatt impact on the Ontario system of a 1 degree Celsius increase in the summer. Using their model, such calculations could also be done for individual zones.

Assessment:

1. The IESO procedures seem generally to be well thought out. They account for the influence of weather on peak demand. They also permit quantification of extreme weather on peak demand projections.
2. The IESO model focuses on projecting profiles. It is a model that is concerned with forecasting the 2:00 a.m. load as well as the 6:00 p.m. load. If the focus is on forecasting peaks. and not on the rest of the profile, the one-equation profile cubic spline model that is used may be smoothing the forecast around the peak too much. In other words, the profile model may not capture sufficiently the variation in the peaks. This is a statistical question and issues regarding the probability distribution of extreme values come into play.
3. Fixed geometric weights of 0.5 are used for the factors employment and number of households in the regression model. These weights seem arbitrary.
4. In its upcoming forecast, IESO will alter its method for population projections. It will use Ontario projections by census division from the Demographics Division of the Ontario Ministry of Finance.
5. While a trend variable enters the model to account for changing use patterns and heating/cooling/appliance configurations, there has been no explicit allowance for future changes in real electricity prices.
6. The model and its projections make no explicit allowance for CDM.

Results and Summary:

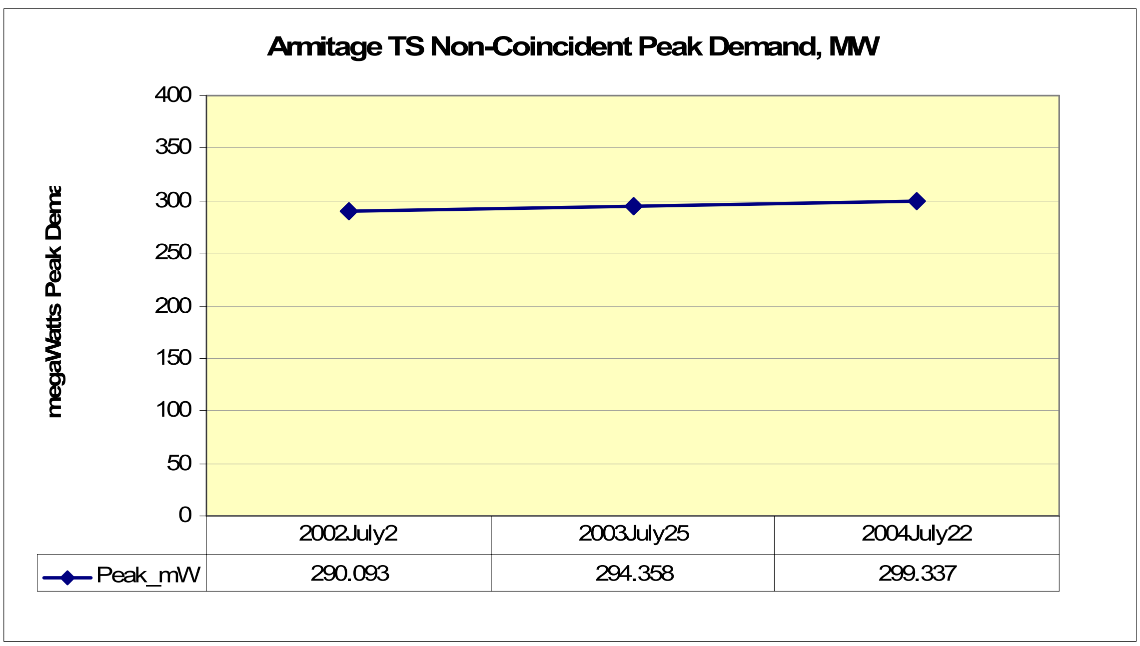
The IESO forecast uses econometric methods for projecting load. For the Essa zone, the annual forecast growth rate for the summer load is 0.31 % for 2005-2014. The annual forecast growth rate the winter load is 0.85% for 2005-2014. Admittedly, the Essa zone envelopes the northern part of York Region and does not correspond to a region within the Region. However, the forecast provides a reference. There are some concerns on the weighting of employment and households in the forecasts. Since our focus is on peak demand rather than load profiles, some modifications on modeling how weather influences peaks is warranted. Like the other forecasts, CDM could be better modeled and the influence of electricity prices needs to be incorporated.

For the IESO forecast, the following table summarizes recommendations pertaining to key evaluation criteria.

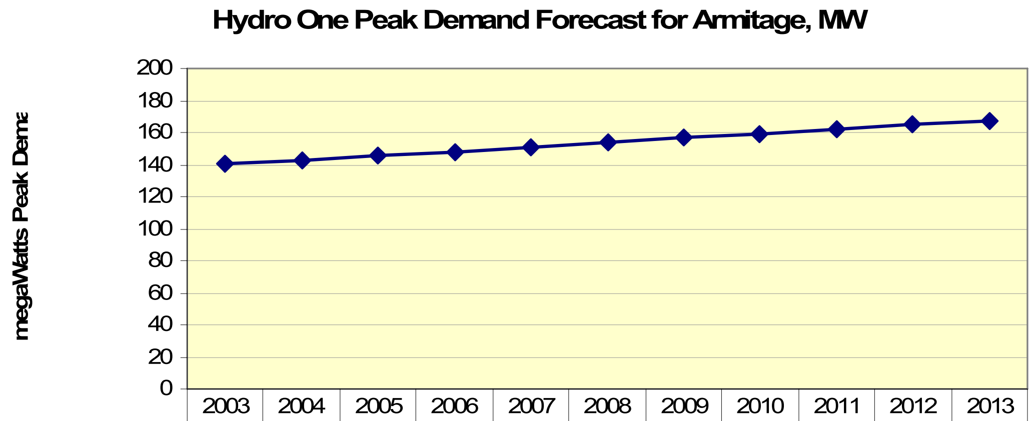
Criterion	Recommendation
Statistical Methodology	Requires further development to be applicable to York Region
Reasonableness of Underlying Model	Requires further development
Input Assumptions	Requires some further development
Treatment of Weather	Modifications are required
Electricity Prices (with a negative impact on growth)	Needs to be incorporated
CDM (with a negative impact on growth)	Needs to be incorporated
Extent of Geographic Coverage	Broader than required

1.2.2.5 Hydro One

Historical Growth in Peak Demand for Armitage TS.



Armitage Hydro One Service Territory Forecast (net of Newmarket and Aurora):



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load (MW)	141	143	146	148	151	154	157	159	162	165	167

Methods and Assumptions:

From our meetings with Hydro One and e-mail correspondence we were able to ascertain the following. For the forecast at Armitage TS, Hydro One forecasts the load growth for Aurora, Newmarket, Markham, Vaughan and Richmond Hill. The overall growth rate for the aggregate of these five utilities is applied to Armitage. Hydro One reduces their aggregate forecast for Armitage by their forecast for Aurora and Newmarket and represents the remainder as the forecast for the Hydro One portion of the load supplied through Armitage TS.

The load forecasts for the five utilities are based on econometric models linking load growth to demographic, economic and weather variables. The specifications for the individual utilities are as follows. For Aurora, the logarithm of the Aurora load is regressed on the logarithm of the Ontario load, the logarithm of the lagged Aurora load and the logarithm of the Aurora population. For Newmarket, the Newmarket load is regressed on the Ontario real disposable income, the Newmarket population, and a dummy variable. For Markham, the summer Markham load is regressed on Ontario real disposable income, the Markham population, cooling degree days and a dummy variable. For Richmond Hill, the summer Richmond Hill load is regressed on cooling degree days, the lag of cooling degree days, Ontario GDP, and the lagged load of Richmond Hill. For Vaughan, the Vaughan load is regressed on Ontario GDP and the number of households in Vaughan.

The population growth rate for York is assumed to be 3.3% per year for 2004 – 2015, with higher growth rates in earlier years. The number of households is expected to grow at a rate of 4.6% per year. Ontario personal disposable income and Ontario GDP are forecast to grow at an average rate of 3.5% and 3.3% per year, respectively.

Hydro One forecasts load at Armitage to grow at 3.1% per year over the period 2003 – 2015.

Hydro One did not reply to us as to how the loads at the other TS stations (Beaverton, Brown Hill and Lindsay) were forecast.

Assessment:

1. No justification for the forecast rate of growth of the aggregate load of the five utilities and using this as the forecast rate of growth for Armitage was provided. Essentially, there is no independent forecast of the Hydro One service territory.

2. While one may question particular specifications for the five utilities, the idea of tying the load forecast of York utilities to province wide variables as well as region specific variables is generally reasonable.

3. A growth rate of 3.3% per year for Ontario GDP seems high. A forecast of household growth of 4.6% per year for York seems high also. Hemson projects household growth of 4.1% per year in 2001 – 2011 and 2.7% per year in 2011 – 2021. Population growth of 3.3% per year in 2004 – 2014 for York seems a little high too. Hemson projects population growth rates of 3.4% per year in 2001 – 2011 and 2.1% in 2011 – 2021.

4. For the load forecasts of the five utilities, only Markham and Richmond Hill incorporate weather, represented by cooling degree days. We would expect weather to play a role also in the other three utilities. However, one might question whether such a broad indicator as cooling degree days is sufficient to explain year-to-year peak variations due to weather, where the peak period of a month is confined to only a few hours.

5. No allowance for the influence of electricity prices has been made.

6. CDM initiatives are not accounted for in the forecast.

Results and Summary:

The Hydro One forecast uses a residual-based econometric method for projecting load in the Hydro One service territory. The annual forecast growth rate for the summer load at Armitage is 3.2% for 2003 – 2013 and for the Armitage Hydro One service territory is 1.7% for 2003-2013. The real concern is the assumption that Armitage's load grows at the same rate as the three large LDCs (PowerStream, Newmarket and Aurora). Like the other forecasts, CDM could be better modeled and the influence of electricity prices needs to be incorporated.

For the Hydro One forecast, the following table summarizes recommendations pertaining to key evaluation criteria.

Criterion	Recommendation
Statistical Methodology	Requires further development
Reasonableness of Underlying Model	Requires further development
Input Assumptions	Requires some further development
Treatment of Weather	Requires further development
Electricity Prices (with a negative impact on growth)	Needs to be incorporated
CDM (with a negative impact on growth)	Needs to be incorporated
Extent of Geographic Coverage	Requires further development

1.3. Incorporation of Conservation and Demand Management (CDM) in Existing Load Forecasts

The following provides a summary of the incorporation of CDM in existing forecasts.

PowerStream:

Moving from 4% growth down to 3% in 2009 is justified on the basis of CDM. By 2014, this reduction of 1 percentage point would represent a 4.7% reduction in aggregate load. However, Hemson forecasts that additional housing will decline from 7120 units per year in 2005 - 2009 to 6120 units per year in 2010 – 2014. Therefore, it is unclear how much of the decline in growth rate is really attributable to CDM.

Aurora:

Method 4 of the Aurora forecasts, which most closely resembles Aurora's recommended forecast, indicates that lower figures for end-uses (as compared with their 2003 forecast) are used in recognition of the "impact from Demand Management and energy Efficiency".

Newmarket:

CDM has not been explicitly accounted for in Newmarket's forecast.

The Independent Electricity System Operator (IESO):

CDM has not been explicitly accounted for in the IESO forecast.

Hydro One:

CDM has not been explicitly accounted for in Hydro One's forecast.

In summary, the impact of CDM on the load forecasts for the York Region merits more careful treatment and quantification.

1.4. Weather Sensitivity

Economic and demographic activity determines the underlying non-weather sensitive base load upon which peak demand is superimposed. But the peak and its variability are strongly related to weather. Most recently, the LDCs in York Region have been peaking in the summer, whereas it appears that the northern parts of York Region have been peaking in the winter. A cursory look at the historical data shows large variations in growth rates from year to year, a large part of which is attributable to variation in weather.

How do the existing forecasts account for weather? Three of them do not. The IESO forecast and the Hydro One forecasts do take weather into account.

As noted, for the underlying models of Hydro One, only the Markham and Richmond Hill forecasts incorporate weather, represented by cooling degree days. However, given that the peak is confined to a very small part of the month, the indicator, cooling degree days, may not be reliable enough. Some indicator of temperature variability within the month might be a better explanatory variable.

The IESO forecasting methodology focuses on projecting hourly profiles. These profiles are modeled as functions of weather variables. By adjusting the temperature by a degree or by hypothesizing an extreme weather day versus a normal weather day, sensitivity of the load profile can be explored. For example, Table 4.2 of the "10-Year Outlook: Ontario Demand Forecast" (March 31, 2004) shows an increase in summer peak load in the order of 11% and an increase in winter peak load in the order of 8% due to extreme weather.

Given that the IESO forecast relates to a much more diversified load than the individual York Region forecasts (either at the utility level or at the TS), we would expect that weather sensitivity would play a bigger role at the York Region level than what IESO is allowing for. In addition, by the very nature of the cubic splining process performed in the IESO modeling, and the resulting smoothing of peaks, we suspect that the IESO procedure underestimates the weather sensitivity of peak demand.

1.5. Overall Assessment

The focus of our analysis is on forecasting peak demands for component geographic areas of York Region. The growth and movement in peak demand can be thought of as having two components. The first is the growth attributable to economic activity, demographic growth and electricity pricing and conservation related policies. The second is the variation in peak due largely to weather.

Recommendation 1: Electricity prices and their future rate structures should be accounted for in forecasting.

With respect to the first component, all of the forecasts that we have reviewed, with varying degrees of emphasis, use explanatory variables drawn from some subset of economic activity, population, number of households, or just underlying trend. Electricity price, a key variable has been ignored. With expected increases in the real price of electricity, this will be a major determinant of future demand. Own-price elasticities in the range of -0.25 to -0.40 for a utility are found in the literature. For example, a 30% rise in the real price of electricity, over say a five year period, could produce a 10% drop in demand, other things equal.

Furthermore, the electricity price structure is now changing and will change further in the future. For those with smart meters, the new time-of-use residential rate proposed for April 2006 shows a price of around 14.2 cents per kWh (9.3 cents per kWh + delivery charges) in the peak time of the day, compared with a current price of around 10.7 cents per kWh. This will significantly affect air conditioning loads in the summer.

Recommendation 2: Forecasts at the regional level should be consistent with province wide forecasts.

Currently there are significant differences in projected growth rates across different forecasts, varying form 0.3% per year to 4.0% per year. While some of this is attributable to different geographic areas and differences in methodologies, some of this clearly is due to differences in assumptions about underlying growth rates in demographics and economic activity. Hydro One assumes a growth rate of 3.5% per year in real GDP. The IESO’s index of economic activity is hypothesized to grow at an annual rate of 1.4% per year. Hydro One projects population growth of 3.3% per year in 2004 – 2014 for York. Hemson projects population growth rates of 3.4% per year in 2001 – 2011 and 2.1% in 2011 – 2021.

In summary, underlying assumptions about changes in inputs, such as economic activity used at the regional level, must be consistent with similar assumptions at the provincial level.

Recommendation 3: An independent load forecast for Hydro One’s service territory should be provided.

The growth of electricity consumption in Hydro One’s service territory should be better quantified. The assumption that the growth of demand in Hydro One’s service territory is the same as that of York’s local distribution companies is not substantiated. An independent forecast, rather than a residual-based forecast, is warranted. This is particularly relevant, because the Armitage peak is sometimes occurring in the winter and the winter peak does not come from Newmarket and Aurora.

Recommendation 4: Incorporate the load impacts of future CDM programs.

Conservation and demand management should be addressed in the forecast. It is understandable that CDM may not have been given much attention in past forecasts. However, since governments at the national and provincial level are now promoting a new climate of conservation and demand management, future forecasts should take CDM into account.

Recommendation 5: The variability around the base component, mostly attributable to weather, needs to be quantified in forecasts for York Region, for both the winter and summer peaks.

The forecasts of the LDCs are either trend-based or closely tied to Hemson population and household projections. These approaches lend themselves more to kWh forecasts than to peak demand forecasts. Another way of looking at these approaches is to regard them as forecasting the first, or base, component of peak demand. The second component relates to variation in weather. Depending on the appliance and heating/cooling configurations of a utility's service area the sensitivity to weather may vary. Looking at the more diversified loads that IESO is forecasting, this variability is at least 10% of the load.

Recommendation 6: New independent peak demand forecasts addressing Recommendations 1 to 5 should be constructed for York Region, with particular attention to the transmission stations (including Armitage) in the northern part of the region.

For the reasons we have discussed, the existing forecasts are not sufficient to draw upon for providing a reconcilable and credible forecast. The new independent forecast should focus on both the summer peak and the winter peak. While the LDCs in York Region are peaking in the summer, the northern part of the Region is peaking in the winter.

Part 2: Conservation and Demand Management

2.1 Introduction

Conservation and Demand Management (CDM) is a newly minted term intended to include a range of energy efficiency and demand management programs that have been referred to more commonly as Demand Side Management (DSM) and Demand Response Programs (DRP). CDM programs include:

- **DSM** – usually including energy efficiency activities by end-use customers. DSM programs have encompassed a range of activities from installing low flow shower heads in homes through to retrofitting high efficiency electric motors in industrial applications. Most DSM programs depend on the decisions of end use customers regarding technology choices, or changes in how they use energy technologies, for their success.

- **DRP** – typically have involved either the reduction of the total energy usage by a commercial or industrial customer or the shifting of load out of peak periods; there have been a few residential programs.

    - **Load displacement** has been achieved primarily through distributed generation by end use commercial/industrial customers such that a significant amount of load is eliminated from the grid of the jurisdiction. Load can be reduced in the residential sector through conversion of energy consumptive equipment and appliances from electricity to other fuels, typically natural gas.

    - **Peak load reduction** (long term) is commonly achieved through the shifting of a customers' load out of high peak periods into off peak periods. This load shifting is typically motivated by higher rates during the on-peak times and lower rates during other times. Often these programs stimulate peak load reduction during the summer or/and during the winter. The typical summer peak load reduction programs such as time-of-use programs operate only during the summer months.

    - **Peak load reduction** (short term) is usually the result of emergency or day ahead curtailment programs where large commercial/industrial customers are paid to reduce demand during emergency or planned high peak periods and, occasionally, penalized when they do not comply with promised curtailments.

The current slate of CDM programs in York Region is described in part 2.2. A review and assessment of CDM programs in general are provided in part 2.3 for DSM programs and in part 2.4 for demand response programs. Part 2.5 summarizes impacts reported in other jurisdictions and indicates possible savings from current and proposed programs in York Region.

2.2 The Current Slate of CDM Programs in York Region

Michael Agrell

Contents

Public policy and the demand for electricity

The growth in the demand for electricity can be analyzed in two ways, a top down, or macroeconomic approach, or in a bottom-up, end-use manner, looking at the individual ways that electricity is used. In the macro approach, the demand for electricity is seen to grow as the economy grows. A smart forecast will recognize that the different sectors of the economy are growing differently, and that different sectors of the economy use electricity differently, and with different intensity. Government policy with respect to interest rates, taxation, etc, can be seen as influencing economic activity, and hence the demand for electricity.

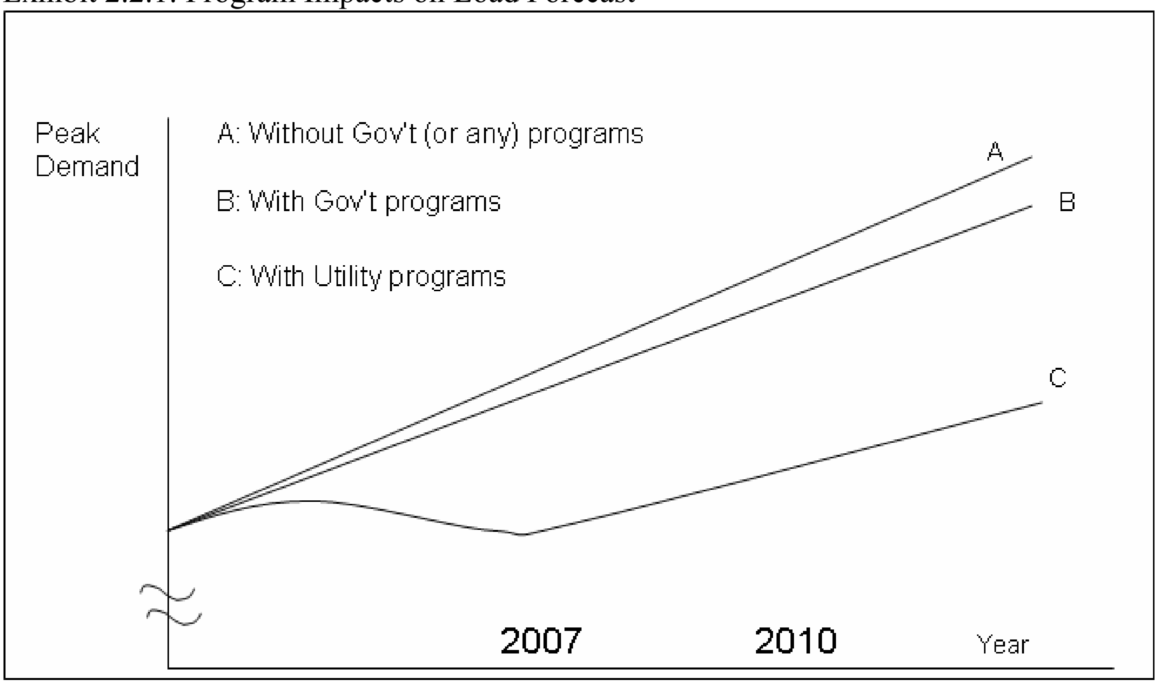
The demand for electricity can also be approached in a bottom up or end use manner. This considers, for example, the number of appliances and their typical use. The total demand is the aggregate over all technologies. However the efficiency of appliances that use electricity, and the way that we use them is also subject to government policy, regulation and influence. Building codes and appliance efficiency standards for example have been steadily improving the efficiency of use. Public education programs influence use patterns and increase awareness of alternative technologies. While the federal government can be thought of as the major player affecting overall economic activity, Federal, provincial and municipal governments all influence efficiency standards. The impact of all these programs and initiatives is to reduce the demand from what it would otherwise be.

The electricity distribution companies can also, within the framework set out by the provincial government, spend moneys and run programs to further reduce the demand for electricity.

These three levels of impact are shown diagrammatically in Exhibit 2.2.1. It should be noted that this is simplified picture and that many grey areas exist. For example municipal governments may promote participation in Federal programs, and the Ontario Government has instructed the province's electric distribution companies to make efforts to reduce their peak demands and to install 'smart' meters.

The following sections describe some of the activities and programs that are currently underway to influence the demand for electricity. They are approached in the order outlined above. Federal and Provincial initiatives to improve efficiency of use are described first, and then specific utility delivered programs are covered in the following section.

Exhibit 2.2.1: Program Impacts on Load Forecast



Some Federal, Provincial, Local and Other Initiatives

Federal initiatives these days are largely driven by the need to met Canada's Kyoto commitments, and their programs, such, as the One-Tonne Challenge are thus primarily aimed at reducing atmospheric emissions through conservation measures. Most of the programs are run by the Office of Energy Efficiency (OEE) that is part of Natural Resources Canada. They are organized on a sector basis, and some of their programs in the residential, commercial and industrial sectors are described below. Further details can be found on the NRC web site at: NRC Portal. In the residential sector there is a wide range of programs including Energuide for Houses, Appliances, and Heating and Cooling equipment, EnergyStar, R-2000, and the One-Tonne Challenge. The chief offering in the commercial sector is the Model National Energy Code of Canada for Buildings 1997 (MNECB). This contains cost-effective minimum requirements for energy efficiency in new buildings. Natural Resources Canada has programs for the industrial sector in the following areas, financial assistance, technical information, regulations and standards, leadership and networking opportunities, and training and awareness.

Ontario's programs, while having an environmental underpinning, seem to be largely driven by the looming shortfall in electricity capacity. The Province is in the initial phase of its declared aim of moving towards a Culture of Conservation, as well as setting up some of the institutional framework, and has moved to improve efficiency standards. These code changes will have to be factored into any new load forecast.

The Provincial government has also given the electric distribution companies money for conservation and demand management programs. This initiative is described in the following section.

Other bodies encouraging conservation in Ontario or across Canada include:
the Toronto Region Conservation Authority (TRCA), the Federation of Canadian Municipalities (FCM), and The Canada Green Building Council (CGBC).

The Natural Gas companies (Union and Enbridge) also deliver conservation programs to their customers. More details of these activities can be found on Enbridge's web site at: Enbridge

Some details of the programs are given in Appendix B1.

While there are a lot of programs out there, they are generally information programs. Where financial incentives are offered, they are generally a "drop in the bucket", i.e. very small compared to the cost of projects.

Distribution Company Programs

After the de regulation of the electricity sector in the mid 1990s, neither the distribution, transmission or generation companies had a mandate to pursue Conservation and Demand Management (CDM) activities. With the recent tightening in the supply position, the Ontario Minister of Energy has called for the creation of a "Conservation Culture" in the province. He has established two objectives for the electricity sector and electricity customers. First, he has targeted a reduction in Ontario's peak demand for electricity of 5% by 2007. Given that overall load growth in the province was forecast to be about 1%[1], if successful this will effectively mean that there is no or negative growth in peak demand over the period. Second, he has committed to the installation of 800,000 SMART electricity meters by 2007, and the full deployment of SMART meters for all

[1] According to the IESO 2004 load forecast.

electricity consumers by 2010. To finance the distribution companies CDM efforts, the Minister tied an increase in allowable return, to investment in CDM initiatives. The Minister also encouraged partnerships with government bodies and other agencies, such as Natural Resources Canada and the Canadian Federation of Municipalities, and with local community-based conservation agencies and authorities, some of which were described in the previous section.

In October 2004, the Ontario Energy Board (OEB) issued a procedural order that addresses applications for CDM plan approval, and, since then, has approved the plans of all four utilities in the York Region. These plans are summarized and analyzed below.

With regard to Smart meters, the OEB submitted its implementation plan to the Minister on January 26, 2005. The proposed plan identifies the mandatory technical requirements for smart meters and the support systems distributors will require; sets priorities for implementation in order to meet the government's targets; identifies regulatory mechanisms for the recovery of costs; and identifies how barriers can be overcome. In addition, the report addresses competitiveness in the provision and support of smart meters and the need for and effectiveness of non-commodity time of use rates. The Board's plan is to encourage large distributors to carry out an initial set of pilot programs using dedicated conservation and demand-management funds during 2005 to gain useful information about the installation and operation of smart meter systems before making final decisions on the particular system that they intend to choose. The Board expects distributors who have held pilot projects to share lessons learned with other distributors.

The OEB also called on the Independent Electricity System operator (IESO) to identify constrained areas for priority installation of smart meters. The OEB's plan proposes that the costs be included in the distribution rates as soon as a distributor starts to install smart meters.

The activities of the four York Region Distribution companies are described below. The material is taken from the plans submitted to the OEB by the distribution companies. The OEB's summary of the plans, and their decision and orders governing the plans can be found on the OEB website at: http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_distconservation_applications.htm

The Plans themselves can be found on line. PowerStream's can be found at: http://www.oeb.gov.on.ca/documents/dcdm_powerstream_141204.pdf

Aurora's will be found at: http://www.aurorahydro.on.ca/conservation_programs.htm
Aurora is included separately, despite of the proposed merger with PowerStream, as it made and published its plans when it was an independent company.

Newmarket Hydro's plan can be found on their website at: http://www.nmhydro.ca/pdf/Final%20Order%20Application_NDA.pdf

Hydro One's plan will be found at: http://www.hydroonenetworks.com/en/regulatory/oeb_applications/RP-04-203_EB-04-533_EB-05-198_H1N_H1B_CDM_Application_and_Evidence.pdf

Understanding of the both the CDM and Smart meter programs was supplemented with conversations with PowerStream, Hydro One, and Newmarket Hydro.

A description of each program, taken from the company's submissions, is given in Appendix B2.

The table below allows comparison of the activities of the distribution companies in the Residential and Small Commercial sectors, and the Commercial, Industrial and Institutional sectors. In some cases the companies programs cover multiple sectors, in which case it has been entered in both tables.

- When reading the material below it should be borne in mind that that the supply problem is essentially a summer peak problem, and so programs are needed that address summer loads, air-conditioning loads, and price responsive programs (based on smart meters) for example.
- Given the sensitivity of load to extreme weather, and the fact that this is when problems are most likely to appear, the program design and assessment must be such as to recognize the natural desire to circumvent measures in extreme conditions.

Some of the utilities initiatives have been characterized as pilots. This means that initial spending will be made to resolve issues in program technology, delivery channels, etc. In most cases the budget includes monies for a full-scale follow-up. However, these programs should be considered as more problematic, and more likely to have a delay before they have significant penetration.

Based on 2001 and 2002 actual loads, the proportion of loads of Armitage going to Aurora, Newmarket and Hydro One are around 23%, 37% and 40%, respectively. Each utility is also expected to contribute to the growth in demand. Therefore the programs of all three of these companies are of significance.

Residential and Small Commercial

Program Type	PowerStream	Aurora	Newmarket	Hydro One
Co-branded mass market program (education and promotion	Program	Program	Program	Program
Smart meter	Pilot	Pilot	Program	Program
Interval Metering				Pilot
Design	Program		Program	

Program Type	PowerStream	Aurora	Newmarket	Hydro One
advisory/audits/retrofits			(Homeworks)	
Load control	Program		Pilot (Gateway-complete)	Program
Social/low income housing	Program	Program	Program	Program
AC upgrade		Pilot		
Residential real time monitoring				Program

Commercial, Industrial and Institutional

Program Type	PowerStream	Aurora	Newmarket	Hydro One
SMART meters	Program		Program[2]	Program
Interval Metering				Pilot
Time-of-Use				Pilot
Energy audits, retrofits and partnerships	Program		Program [3](Ecosystem[4])	
Leveraging conservation and LM programs	Program			
Demand response	Program			
Design advisory	Program	Program		
Big Box retailer retrofit		Pilot		
AC conditioner upgrade		Pilot		
Manufacturing energy upgrade		Pilot		
Power factor corrections		Program		
Institutional		Program (buildings)	Programs (schools & street lighting)	
Festive lights		Pilot		

[2] While not described in Newmarket Hydro's published plan, the company does in fact have a program of installing meters in Commercial and Industrial premises. Currently the focus is on customers with loads greater than 500 kW. In addition, as part of the Ecosystem Audits, at each audit site a meter is installed, if it not there already.

[3] Being a general audit, and energy service company Ecosystem is capable of recommending and implementing a range of efficiency and demand management techniques. Hence the program fits in a number of categories. Probably more than have been identified.

[4] Ecosystem is an independent Energy Services company. It is the largest energy efficiency contractor in Quebec.

Program Type	PowerStream	Aurora	Newmarket	Hydro One
Load Control/Management			Program (Ecosystem)	Program
Farm Energy efficiency				Program
Distributed Energy	Program			
Standby Generators	Pilot			

Newmarket, has not, like the other utilities, identified a full range if independent programs. Rather it has a partnership with Ecosystem is for the delivery of comprehensive energy management solutions. Thus while compared to the other utilities, Newmarket seems to be light on Demand Management programs, and programs in the Commercial and Industrial sectors, the partnership with Ecosystem is capable of delivering many different types of energy efficiency and management solutions, and of leveraging the energy programs of others, e.g. Enbridge and NRC.

All the companies also have initiatives to reduce losses in their systems.

Distribution Network Loss Reduction

Program type	PowerStream	Aurora	Newmarket	Hydro One
Feeder Phase balancing	Program			Program
Power Factor correction	Program			Program
Others	Program	Pilot (loss reduction)	Program (revised equipment specs)	Program

The table below gives the amounts the companies are planning to spend over the period 2004 – 2007. It includes both capital and operation expenditures. The company's plans usually include more details.

Funding $M

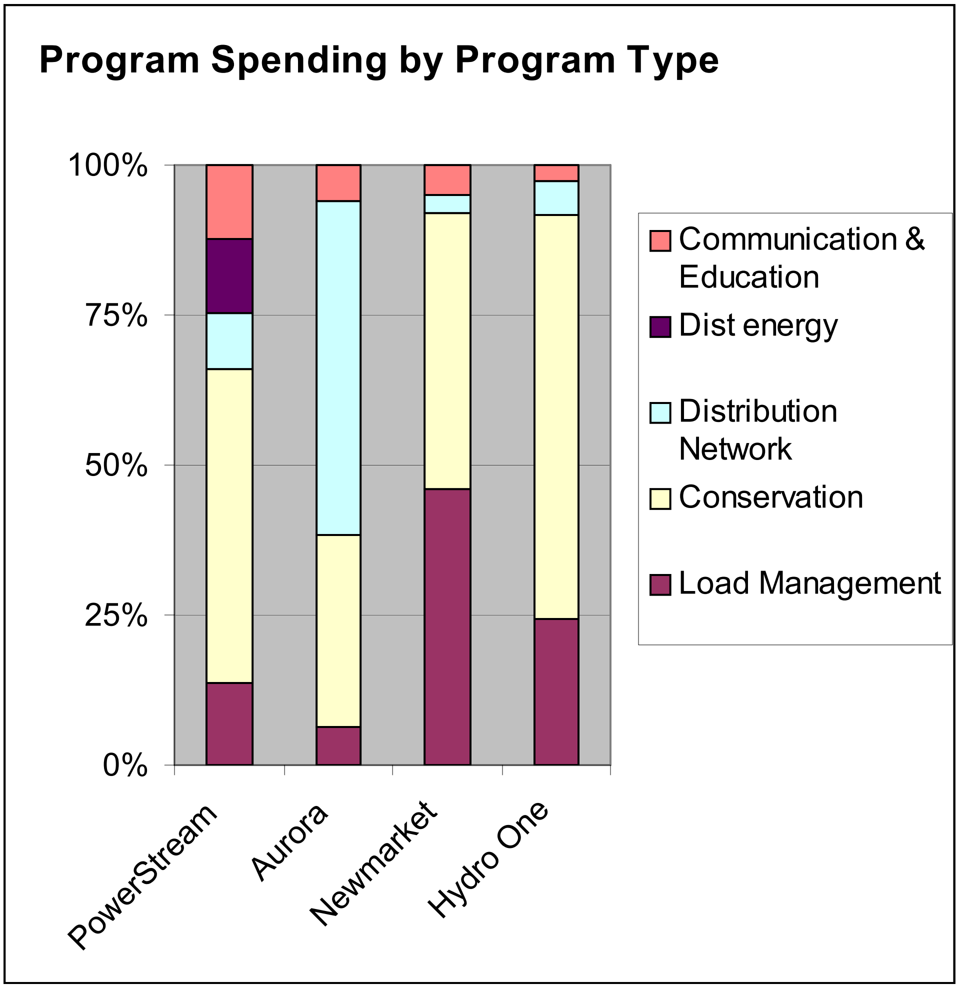
By Program Area

	Power Stream	**Aurora**	**Newmarket**	**Hydro One (Before board redirect)**
Smart Metering	1.2	0.115	Not included	14.9[5]
Load management	0.7	0.040	[6]	8.7
Conservation	2.7	0.200	0.98	9.2
Distribution Network	0.48	0.350	0.03	2.0
Dist energy	0.64	0	0.00	0.0
Communication/education	0.64	0.037	0.05	1.0
Program Management and research	Inc above	0.075	.0.22	3.7
Total $M (2004-07)	6.4	0.82	1.27	39.5
MW	1300	72	142	3300
$/kW peak demand	4.89	11.347	9.01	11.97

Looking at the spending per total load, Newmarket, Aurora and Hydro One are spending very comparable amounts. PowerStream's spending is low in comparison with the other three. In absolute terms the amounts the distribution companies have to use, to get 5% reduction in peak demand, seem very low. Part 2.3 addresses this in more detail.

The graph below allows comparison of the percentages being spent in the different program areas. In this chart, spending on smart meters has been excluded. Also the program and administration costs have been shared pro rata across the programs. Hydro Ones spending has been redirected in line with the OEB's direction.

[5] These monies will be redirected to C/I conservation programs, including reduction of line losses (Private conversation)
[6] Not separately identified, included in the conservation programs.



Newmarket does not split its budget between conservation and demand management activities. In fact the split will be customer driven, depending on the opportunities that are identified through the audit process. For the purposes of this chart, a 50:50 split has been assumed.

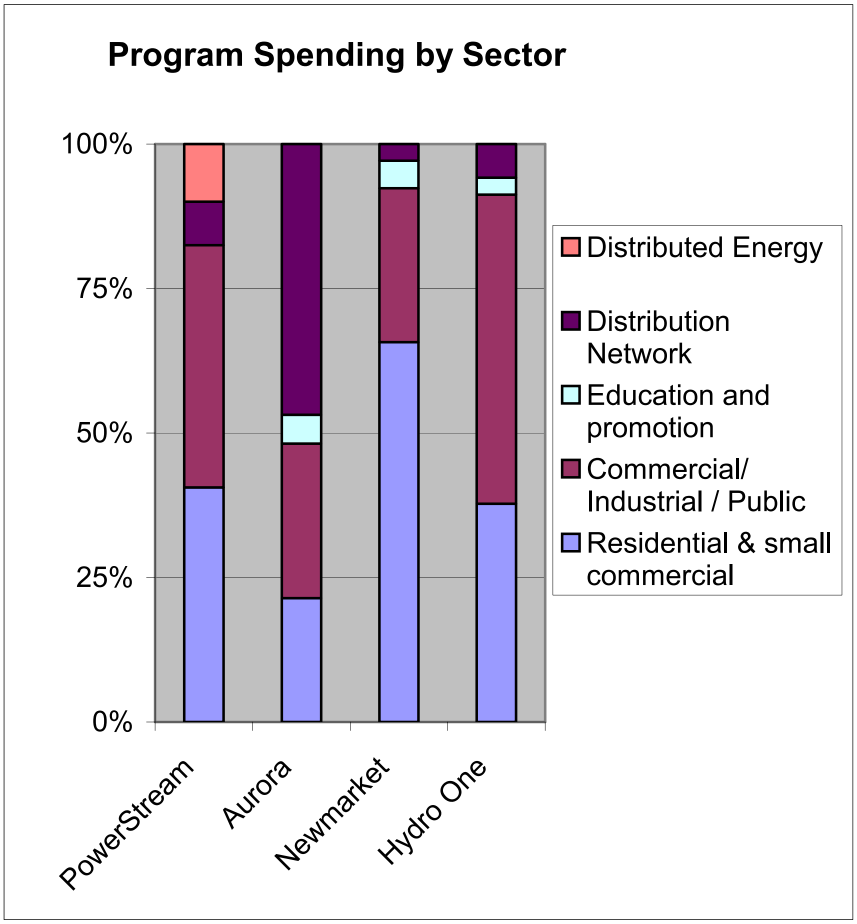
Aurora seems to be spending way more on its Distribution network than the other utilities. Whether or not this is the most way to spend the monies will be addressed in part 2.3.

Spending By Sector ($M)

	Power Stream	Aurora	Newmarket	Hydro One (Before board redirect)
Residential & small commercial	2.60	0.162	0.69	20.2[7]
Commercial/ Industrial	2.69	0.121	0.28	11.2[8]
Public Infrastructure	0.0[9]	0.075	0.0	0
Education and promotion	0.0	.037	0.05[10]	1.0
Distribution Network	0.48	0.35	0.03	2.0
Distributed Energy	0.64	0.0	0.0	0.0
Program Admin	Inc. above	0.075	0.22	5.1
Total	6.41	0.82	1.27	39.5

The chart below shows the percentage spending of the utilities in the different program areas.

[7] Redirection will reduce this by approx 7.2 M
[8] Redirection will increase this by approx 7.2 M
[9] Included in C/I above
[10] In addition to these funds, Newmarket Hydro will be spending $20 k to start the development of a Social Housing education package. They will also be providing $50 k in funding to environmental education organization.(Earth Rangers)



In Newmarket, a significant portion of residential housing is electrically heated, which explains why the utility spends more than its neighbouring utilities in this sector.

Conclusions

- PowerStream appears to have a comprehensive set of initiatives and, and is working appropriately with other agencies in the region to maximize its effectiveness, despite spending less per unit of load than the other utilities.
- Aurora has a reasonable set of programs, given its comparatively small size. But is spending far too much on cutting its system losses. If the proposed merger with PowerStream goes ahead, then the broad based programs and approach being instituted by PowerStream can only work to further improve the effectiveness of the CDM efforts in Aurora.
- Hydro One has a reasonable range of programs; however they all in very early stages of development, and few details are available, except in the area of loss reduction. Partnerships and working with others, while appearing in their general strategy statement, do not appear to feature highly in their plans. Given the broad geographical nature of its service territory, its impact on the loads served by Armitage TS and Brown Hill TS is likely hard to assess. However they have chosen Newmarket as one of the communities to pilot their residential load control project. This project will run from July 2004 to Sept 2005. The pilot is

testing the technology, take-up rates and load control actually achieved. The technology appears to be working and refusal rates were low. The lack of very hot days in summer of 2004 means that there are no indications yet as to the effectiveness in controlling load.

- Another point about Hydro One is that they have relatively heavy conservation component. This means that demand management opportunities aimed at summer peaks might still be available.
- Newmarket's approach of partnering with two major Energy Service Companies, should give it maximum bang for their buck. Specific programs in play else where that might be appropriate in Newmarket include:
  - Air Conditioning focused programs for both residential and the C/I sectors
  - A broader community based approach to influencing standards, codes and plans, to encourage sustainable building practices. (As per PowerStream)

With respect to all the companies it has to be noted that they

- are all effectively starting from scratch
- have very limited funds
- have a very limited time to deliver results. Effectively they have to design programs, test and deliver them and get results in a 2-year window.
- have no guaranties of future funding

In light of this it will be surprising if the 5% target reduction is achieved. A detailed analysis of the probable impact of the proposed programs, and further suggestions as to additional programs will be found in parts 2.2 – 2.4.*)*

The Request for Expressions of Interest (RFI)

In anticipation of the need for further resources in the Newmarket area, on May 2nd 2005, the OPA issued two Requests for Expressions of Interest, one for Generation Resources, and one for Verifiable Electricity Demand Reduction (DR) in the Northeastern York Region. The full RFI can be found at OPA DR RFI. The RFI for CDM was designed to identify parties capable of providing demand reduction projects, prior to conducting a competitive bidding process. The bidding process could lead to one or more contracts, subject to the OPA's recommendation to proceed with remedial actions that include demand reduction measures, and approval from the OEB.

The RFI asked for capacity of greater than 1 MW, expecting respondents will aggregate the efforts of multiple electricity consumers. Demand reductions were asked for that would be available during summers and winter peak load periods experienced in the Armitage TS service area. The demand reductions were expected to be verifiable, to be able to respond to price signals or directives from the Independent Electricity System Operator (IESO). The respondents were warned that they would be competing with generation and transmission options, and that this might require the program to obtain a significant portion of its revenues from the customers benefiting from the reductions in energy consumption. Payment is anticipated to be based on those set out for DR projects in the 2500 MW contract. On-site generation from clean fuels was also eligible.

Several expressions of interest have been received and will be described elsewhere.

These programs are expected to be incremental to the utility programs and hence are not included in the analysis of the load forecast.

Utility driven CDM post 2005
In the longer term there are three things that should be borne in mind in forecasting the level of future CDM activity and hence the load forecast.

Firstly, recently (April 20, 2005) the Minister appointed Mr. Peter Love as Chief Energy Conservation Officer, to head the province's new Conservation Bureau, a division of the Ontario Power Authority, In addition to helping the government meet its target to reduce peak electricity demand growth in Ontario by five per cent by 2007, the Conservation Bureau will:

- Develop province-wide conservation programs to help consumers save energy and save money
- Promote energy conservation and the efficient use of electricity
- Assess the technical, economic and market potential for conservation in the province
- Report on Ontario's progress in achieving its conservation targets and assess what further action is required.

The OPA has not had time yet to make initiatives, but its influence is expected to be felt post 2007 and must be factored into long-term load forecasts.

The second factor is that in its guidelines for the preparation of the 2007 rates cases that the distribution companies must file, the OEB has made it clear that as well as being compensated for the reduced load of such programs, there will be incentives for the shareholders of the companies as well. It must therefore be expected that distribution company activities will continue after 2007, but at what rate is completely unclear. Many utilities will want to wait and see the details before they start planning longer-term activities.

And finally, the program to install smart meters, currently scheduled to be complete by 2010, will leave an unprecedented capability for the provinces electricity users to respond to the pricing signals that will accompany peak demands. This capability to respond to price signals can be expected to have significant impact on the growth in peak demand in the future, but this depends on the tiered pricing being passed on to end-use consumers, and on its continuation into the future.

2.3 Assessment of Demand Side Management Programs: Experience Elsewhere, Potential Impact & Recommendations

In 2003, Hydro One and the York Region utilities conducted a joint study to review trends in electricity demand as part of their planning for capacity requirements over the next 10 years. Although that study – the *York Region Supply Study, Adequacy of Transmission Facilities and Transmission Supply Plan 2003-2013*[11] – reported that investment in upgrading and new facilities will indeed be necessary, no mention was made of the possibility that some of the projected shortfall could be dealt with by reducing total and peak electricity demand through conservation and demand management (CDM) programs. Yet, only two years later, these same local distribution companies (LDCs) are involved in developing and implementing numerous ambitious CDM programs and it is clear that attempts to reduce electricity demand and entice other demand responses from customers will be a part of the overall effort to assure that there are ample supplies of electricity in York Region.

This sudden change has come about as a result of government policy. As part of its overall plan to ensure adequate electricity supplies, the Ontario government has set out to create a 'conservation culture' in the province, with an initial target of reducing peak electricity demand by 5% by 2007. CDM programs designed and implemented by the LDCs have an important role to play in achieving that target and in establishing the overall culture of conservation; and to the extent that the utilities operating in York Region are able to contribute their full share in this role, their CDM activities will also help to deal with the transmission needs in the Region.

In this section we consider the conservation aspects of these activities; the demand response aspects are discussed in the next section. Three issues are discussed: (1) whether one should be confident that the LDCs are likely to be able to make the contribution to reducing peak electricity demand that is expected of them; (2) the evidence that DSM activities do actually reduce electricity demand is briefly reviewed; and (3) the difficulties involved in forecasting the impacts of CDM in York Region at this particular time are discussed and a recommendation for a limited focused analysis of projected impacts is made.

Developing CDM programs in Ontario's Utilities

One reason why the challenge facing the LDCs is large is that to a great extent they are starting from 'ground-zero'. Although Ontario Hydro carried on a variety of conservation activities in the period 1987-94 – at that time they were referred to as demand-side management programs – the 'corporate memory' of them has been effectively dissipated. Until the announcement of the government's new electricity policy a little more than a year ago, Hydro One and the smaller LDCs had no need to concern themselves with CDM. The people involved in Ontario Hydro's activities have long ago moved on to

[11] Published July 10, 2003. Available at www.hydroonenetworks.com/en/community/projects/transmission/northern_york_joint_study.pdf

other things; and anyway in the past the LDCs had no need to employ staff with such expertise. Thus it's clear that the utilities are facing a steep learning curve.

There are several factors that should help them to rise to the challenge and some pitfalls to be concerned about. We describe the pluses and minuses below.

Defining proximate goals

Because there are many different ways to pursue conservation goals, the first task for the LDCs has been to decide which types of programs to undertake. On this they have had some help, since the Ontario Government has already made some choices for them. At the centre of the Government's plan is the deployment of SMART electricity meters that will allow Ontario electricity users to monitor their consumption and respond to price incentives designed to facilitate better load management. The plan is to have 800,000 SMART meters installed by 2007 and full deployment for all electricity consumers by 2010. Thus a first step for the LDCs is to run pilot programs on SMART meters. The Government has also asked them to work at reducing 'system losses' in their transmission of electricity.

On the other hand, beyond these two areas, the Government has simply encouraged the LDCs to begin investing in local, community-based conservation programs. This presents a more wide open challenge and requires knowledge and expertise not normally found in the staff of an LDC. It also requires the development of long-term strategies and commitment; and, in regard to some programs, the integration of the utility's activities with programs at provincial and national levels. There is evidence that DSM programs work much better when they are not done in a piecemeal way.[12]

An institutional framework

Running ambitious CDM programs is complex and involves a lot of resources. The danger that the LDCs' programs will be mismanaged is reduced because the local distribution industry is regulated by the Ontario Energy Board. The costs of running CDM will be covered by the LDC's customers and are subject to the usual scrutiny by the provincial energy regulator. The OEB has already vetted the LDCs initial CDM plans[13]

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[12] See, for instance, M. J. Horowitz, 'Economic Indicators of Market Transformation: Energy efficient lighting and EPA's Green Lights', *The Energy Journal,* Vol. 22, No. 4. With regard to lighting programs in the US, Horowitz says: " … it is far more cost-effective to attempt to transform a national market through long-term … efforts that permit market preferences to evolve and mature, than it is to temporarily manipulate local markets through piecemeal programs that are highly variable from place to place and year to year." (p.121)

[13] See http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_distconservation_applications.htm

and the Board will also monitor the outcomes through quarterly and annual reports.[14] The annual report will require a benefit-cost analysis of each CDM program undertaken.

It is acknowledged that the OEB is itself moving into a new area here and that the rules to which the LDCs will be subject have not yet been fully worked out. However, the Board has been proceeding in this area in an ambitious way through its well-established hearing and other deliberative processes and it therefore has the benefit of information and advice from a wide range of interveners.[15] They also have the benefit of experience from their oversight of successful CDM activities in the natural gas distribution industry.

Additional institutional guidance and support can be expected from the newly-appointed Chief Energy Conservation Officer and the Conservation Bureau that he heads in the Ontario Power Authority. At this point the Bureau is at an early stage of its operation and exactly what it will do is not yet known. However, it's reasonable to expect that it will be a source of information on technical issues (e.g., identifying areas and amounts of conservation potential, assessing programs, providing guidance on strategy development, etc.) and a promoter of conservation at the provincial level. This sort of support would back up the marketing efforts of the LDCs.

While the OEB has an important role in providing an administrative and business framework for the operation of CDM programs, the Conservation Bureau's role will be important in helping to determine the level of commitment and enthusiasm of the LDCs for CDM activities and their long-term strategies. The LDCs have been given an initial push by the Government and this has resulted in a significant set of actions. But this is simply a first step, which stretches only two years into the future; the LDCs have no specific direction on CDM after 2007. Thus the consistency and strength of Government policy on this matter – which will or will not manifest itself in the actions of the Conservation Bureau – is an important question mark in regard to whether LDC conservation activities will play a significant role in ensuring adequate electricity supply in York Region.

Experience from elsewhere

While Ontario did little in regard to electricity CDM in the decade before the current policy was established, the development of CDM flourished in many other places. In some other Canadian provinces (e.g., Manitoba, Quebec and British Columbia), in many states in the US (New York is often mentioned as having excellent programs) and in some European countries, utility-run CDM programs have been saving significant amounts of electricity.

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[14] The quarterly reporting form is available at
http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory_cdmfiling_erforma.htm

[15] The OEB conducted a hearing to examine applications of the LDCs for approval of their CDM plans. Transcripts for Hearing File No. RP-2004-0203 can be viewed at
http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/.

Trends in Canada are well-reported on by the Canadian Energy Efficiency Alliance. Each year, starting in 1999, it has run a survey of activities in support of energy efficiency in all provinces and federal jurisdictions (this includes programs of both utilities and other agencies).[16] From the survey they prepare a report card. In the first survey, in 1999, grades for all jurisdictions ranged between D- and C+. In the latest survey, for 2004, Manitoba, the Federal Government and the Yukon were assigned grades in the A range; five other provinces had grades in the B range. In the five surveys between 1999 and 2004 Ontario's grades ranged between C+ and C-, with the trend being downward.

Similar sources of information on successful CDM programs are available from other countries. For example, for the United States, see the materials produced by the American Council for an Energy-Efficient Economy, such as its report entitled *America's Best: Profiles of America's Leading Energy Efficiency Programs* (March 2003).[17] For experience in Europe see the INDEEP database provided by the International Energy Agency's Demand Side Management Programme.[18]

A brief review of the impacts of CDM programs in other jurisdictions is presented later in this section of the report. The key point here is that a wide range of successful conservation programs have been undertaken in other jurisdictions and have produced results. It follows that *imitation* provides an efficient way for new players, such as the LDCs in York Region, to design their programs. Of course, activities have to be adapted to serve the specific customer base of any given utility; but doing that from a proven starting point is obviously a big advantage.

Sources of expertise and experience

Perhaps the most important reason for optimism in regard to whether York Region LDCs can produce effective CDM programs is that they can benefit from the expertise of highly experienced people through partnering with established agencies and by purchasing the services of specialists on a contractual basis. Especially in relation to energy efficiency programs, the services and programs of government and private-sector agencies can be easily drawn upon. In fact, many CDM programs are centred on helping people and businesses to take advantage of federal and provincial programs. A good example is the possibility to obtain highly subsidized energy audits of residential and other buildings, and then benefit from direct subsidies to help defray the cost of remedying the problems found by the audits. References to such programs and consideration of the possibility of partnering are included in Section 2.2 above and its Appendix B1.

[16]See '5th Annual Report Card' at http://www.energyefficiency.org/.

[17] Available at http://www.aceee.org/.

[18] http://dsm.iea.org.

In regard to hiring expertise, it is important to recognize that a large market has developed – within Canada and worldwide – for the provision of services in support of energy efficiency and related needs. Energy service companies and other specialized consulting firms are available to the LDCs to provide help with program design and implementation. For many CDM activities the LDC simply acts as the conduit for marketing program services – the actual work of the program can be done by people other than LDC-staff. Since many of the people involved in these companies are likely to have worked on CDM activities in other jurisdictions, using their services is a highly effective way of transferring knowledge and the benefits of experience.

The descriptions of the York Region CDM programs in Section 2.2 make it clear that the York LDCs are using the services of established energy service companies. For example, Newmarket Hydro Limited has partnered with two companies: Homeworks, which offers one-stop shopping for household energy efficiency services; and Ecosystem, an energy management company with a strong track record in electromechanical engineering.

Finally, it is useful to note that there are scale economies in the mounting of CDM programs. This introduces an important issue: there are certain kinds of programs that would be better mounted at the provincial or national level than by LDCs, or even groups of LDCs. This is a larger question than can be discussed in depth here, but it is obviously an issue for the Conservation Bureau to take seriously in regard to long-term planning for CDM in Ontario. At the same time, the point is relevant even now, since it is possible for LDCs to share activities. In that regard, the decision of PowerStream to carry on its CDM within a consortium of the province's large LDCs is of interest. This possibility should be considered by the smaller LDCs as well.

A framework for success?

The context described above, within which the LDCs are approaching CDM, provides some reason to be hopeful about the effects of programs to be undertaken by Ontario utilities. While the above discussion provides only background on the undertaking of CDM programs, rather than an examination of the details of the individual programs, it indicates that a framework exists in which program design and implementation can be approached in an efficient and productive way. The program descriptions in Section 2.2 of this report suggest that the York utilities are using that framework effectively.

At the same time, it's important to note that the present activities are only a start. If CDM is to have any significant impact on energy demand and load management, it will be necessary to build on this new initiative. Doing so will depend on the commitment of both the utilities and the Government to CDM goals. Perhaps the most important step that needs to be taken quickly is for the Government and the Conservation Bureau to clarify that they are committed over the long term to giving CDM a substantial role in ensuring that Ontario will have enough electricity. Some guidance as to what LDCs are expected to do after 2007 is needed.

Estimated impacts of utility conservation programs

A variety of quantitative information on the effects of DSM programs can be found in the public domain. There are estimates of the electricity saved from individual specific programs and of the impacts of portfolios of programs on utility loads and regional demand, as well as econometric studies of demand impacts based on regional or national data samples. A full review of such evidence is well beyond the scope of this report. It is useful, however, to report some examples of quantitative impacts to provide some feel for the magnitudes involved.

A useful place to start is to describe some successful programs undertaken elsewhere in Canada. The surveys of the Canadian Energy Efficiency Alliance are again helpful. In 2004 the Alliance undertook to prepare a 'Best Practices' assessment of energy company CDM activities.[19] Six programs were assessed as representing Best Practice; another eight were given Honourable Mention status. To illustrate what is involved; the three of the Best Practice programs that were carried out by electric utilities are briefly described in the box on the next page.

Thus, for example, BC Hydro's Traffic Lighting Program is reported as saving 26.2 GWH annually, roughly equivalent to the energy used annually by about 2600 households in Ontario. Manitoba Hydro's Commercial Lighting program had accumulated savings of 118.5 GWH when the survey report was made.

Some evidence on the size of impacts is also available for the demand management programs of natural gas distributors in Ontario.[20] For instance, Enbridge Gas Distribution, which has had a very extensive set of programs, reports that at the end of its 2002 fiscal year, 39% of its customers (582,839 gas-buying entities) had participated in them. In the first full year of implementation these programs resulted in the saving of 92.4 million m^3 of natural gas, enough to serve more than 32,000 homes. They estimate net energy savings over the lifetime of these measures of $171 million. In the period of the fiscal years1995 through 2002 the cumulative net energy savings due to their conservation programs are estimated at $584.6 million, corresponding to enough natural gas to serve just over 300,000 homes for one year (915.5 million m^3). This is believed to have prevented 1.7 million tonnes of CO_2 emissions, equivalent to having 650,000 fewer cars on the road.

Union Gas has also had substantial results from its conservation programs. From 1999 to 2003, it reports that its programs reduced natural gas consumption by 192.3 million m^3.

[19] See *2004 SURVEY OF UTILITY DSM ENERGY EFFICIENCY PROGRAMS IN CANADA – RESULTS,* available at http://www.energyefficiency.org/.

[20] Information in this paragraph and the following one is from Canadian Energy Efficiency Alliance, *Energy Conservation: Getting Started a guide for Electrical Distributors and their Shareholders on the Investment Benefits of - A Conservation and Demand Management Plan* (2004-12-22; available on the web at LDC Getting Started Guide for CDM)

‘Best Practice’ CDM Projects as evaluated by the Canadian Energy Efficiency Alliance

1. BC Hydro Power Smart Traffic Lighting Program
Direct Energy Savings: 26.2 GWH annually. 99% of eligible lights. Average 85% to 90% savings. Very strong results.
Market Transformation Effects: Almost complete coverage – all municipalities. Market is virtually transformed.
Evaluation Results: Excellent monitoring and verification protocols
Qualitative Assessment/Peer Recognition: BC now has the highest percentage of LED traffic signals in Canada
Innovative Aspects: Unique partnership between utility and municipalities .
Replication Potential: Program now being undertaken in other parts of the country with direct informational input from BC Hydro.
Overall Assessment – Power Smart Traffic Light Program
Very good program with excellent results. It deserves a Best Practice. And is likely one of the top programs. Received highest praise from the Oversight Committee.

2. **BC Hydro Seasonal Light emitting diode (SLED) Program**
Direct Energy Savings: 8.7 GWh
Market Transformation Effects: Has had strong MT effects – SLEDs were hardly available in BC. BC Hydro’s development of supply chain relationships at the national level has led to spill-over in other provinces
Evaluation Results: Full evaluation results using standard protocols. Seems expensive, however the MT impacts may justify the cost.
Qualitative Assessment/Peer Recognition: Some media coverage and has been referenced in other best practices efforts.
Innovative Aspects: BC Hydro implemented a 2 phased approach. In 2002, successfully raised awareness of the new technology by providing 20K LED strings to a few locations. In 2003, educational material & $5 coupons used to create even more demand. Direct acquisition program that engaged the distributors.
Replication Potential: Some – especially for utilities that have large market power. Represents an excellent example of procurement program using utility purchase power. Niche market may make replication easier.
Overall Assessment – SLED Program
Very good program and unique approach to the market. Recommended for a Best Practice based on its unique approach, MT attributes and strong results. Oversight Committee noted the success of this program.

3. **Manitoba Hydro Power Smart Commercial Lighting Program**
Direct Energy Savings: 118.5 GWH cumulative and 10.8 gW.h in 2003 alone. Very strong results Nearly 3700 projects.
Market Transformation Effects: Has led to a large decrease in price and increased availability of product which is a classic indicator of MT.
Evaluation Results: Full evaluation results using standard protocols
Qualitative Assessment/Peer Recognition: Many testimonials and significant market support.
Innovative Aspects: Includes an extensive educational/training component, lots of R&D support, outreach to targeted sectors. Very strong design components.
Replication Potential: Has been used as a model internally.
Overall Assessment – Power Smart Commercial Lighting
Very good program with excellent results. It deserves a Best Practice based on its results, its MT attributes and its overall approach. The Oversight Committee provided strong support for this program.
Source: CEEA, *2004 Survey Of Utility Dsm Energy Efficiency Programs In Canada – Results*

The impacts of broader energy efficiency programs on electricity demand are also indicative of the potential effects of utility-based programs. A member of this research team was involved in a study of a community-based program in Espanola, Ontario, which experimented with the offering of high incentives in the hope of achieving high savings.[21] The study shows that measures directed at more efficient space-heating reduced energy consumption by about 2900 kWh per year (a 27% saving). The water-heating measures show an annual savings of about 8% (200 kWh) per year. For other uses, the estimated saving was about 175 kWh or 2% per year.

At a regional level an illustration from the United States is interesting. A 2002 report by the Southwest Energy Efficiency Project (SWEEP) cites large benefits for the southwest US of the forecasted achievement of its 'High Efficiency Scenario':[22]

- Reducing average electricity demand growth from 2.6% per year in the Base Scenario to 0.7% per year in the High Efficiency scenario;
- Reducing total electricity consumption 18% (41,400 GWH/yr) by 2010 and 33% (99,000 GWh/yr) by 2020;
- Eliminating the need to construct 34 500MW power plants or their equivalent by 2020;
- Saving consumers and businesses $28 b. between 2003 and 2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45%) and regional personal income by $1.34 b. per year by 2020; and
- Reducing carbon dioxide emissions by 13% in 2010 and 26 % in 2020 relative to the emissions in the base scenario.

SWEEP has estimated a benefit-cost ratio for the programs covered of 4.15 in 2010 and 4.48 in 2020.

It is important to acknowledge that critics of CDM programs call into question the estimates of program-impacts reported by electric utilities and other agencies.[23] Too often, they say, these estimates are based on engineering data about what is possible if new technologies are installed and used properly. The actual results can differ from the projected results. Even *ex post* estimates, based on customer-billing data or other measures can be suspect, in that they typically reflect a mix of behavioral and other effects along with the impact of the CDM measure being considered. For instance, such estimates may not account for the 'free rider problem'; that is, the likelihood that some of the changes would have come about even in the absence of the CDM program being examined. Economists have studied this question extensively by analyzing market data

[21] Dean Mountain, Ron Robinson and Frank Eaton, "Estimating End-Use Specific Energy Savings from a Community Based Energy Efficiency Program: A Bayesian Integration of End-Use and Billing Data" (Working paper, 2002).

[22] Southwest Energy Efficiency Project (November 2002), "The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest," A report in the Hewlett Foundation Energy Series.

[23] See, for instance, P.L. Joskow and D.B. Marron, "What does a negawatt really cost? Evidence from utility conservation programs", *The Energy Journal*, Vol. 13, No. 4.

within a framework that allows them to distinguish the impacts of CDM programs from the normal working of the markets.

This research literature suggests that many utility-based estimates have indeed overstated the benefits of CDM programs, though there is hardly agreement on the extent. For instance, a study by Parfomak and Lave of the programs of 39 utilities in the northeast US and California finds that more than 99% of the reported conservation effects are observable in system-level sales after accounting for economic and weather effects.[24] On the other hand, Loughran and Kulick, using different data sources relating to 324 utilities in the US, find larger discrepancies between utility reported data and what can be observed from electricity sales data. They estimate that DSM expenditures lowered mean electricity sales by between 0.3-0.4 percent, while the utilities themselves estimated reductions of 1.8-2.3 percent.[25]

Two comments are relevant in the present context. First, the results of this kind of research have led to improvements in the methodologies used to estimate program impacts. Second, even where it has been found that actual program impacts are smaller than those originally reported, the more accurate estimates still show that positive impacts have occurred.

Expected impacts of utility conservation programs in York Region

Is it possible to forecast the impacts of the programs being undertaken by the utilities operating in York Region with any confidence? Other than to say that there is every reason to expect them to be positive, the answer is no – estimates of kilowatt-hours of energy saved or kilowatts of peak load reduction are not possible on the basis of available data. Although the Ontario Energy Board invited estimates of the impacts of programs proposed in the LDCs' plans, very few were provided. As reported in Appendix B2, the utilities generally indicated how much money they would spend on their programs and described them in qualitative terms.

It should be noted as well that the amount to be spent by each utility has not been determined by an evaluation of what needs to be done in the province, or in each utility's service region, in order to achieve the target of reducing peak demand in Ontario by 5% in Ontario by 2007. Rather the utilities were given an incentive to spend on CDM by being allowed to increase their rate-generated revenue on the condition that they would use the first year of this incremental revenue to undertake CDM programs. If instead they had been given a target-amount of demand reduction, a forecast of the outcome of the programs would be easier to undertake.

[24] P.W. Parformak and L.B. lave, "How many kilowatts are in a negawatt? Verifying ex post estimates of utility conservation impacts at the regional level", *The Energy Journal*, Vol. 17, No. 4 (1996).
[25] D.S. Loughran and J. Kulick, "Demand-Side management and energy efficiency in the US", *The Energy Journal,* Vol. 25, No. 1 (2004).

With a great deal of additional work, it would be possible to build a bottom-up estimate of the expected results of the CDM plans of the four utilities operating in York Region. We do not recommend doing a comprehensive version of such a forecast for the whole Region at this point. In part this is because information on the impacts of the programs will gradually become available as the OEB collects its quarterly and annual reports from the utilities. Since the overall impact of the conservation programs is not likely to be large relative to the additional capacity needed in the Region, an estimate of that impact may be needed only at the point when planned capacity increases for the Region are being 'fine-tuned'. By that time some of the quantitative information to be collected by the OEB is likely to be available.

It is possible, however, that some more focused study of the potential impacts of conservation and demand response programs would be useful. Certain kinds of conservation programs can produce large effects if appropriate incentives are used. The study of space heating savings in Espanola, referred to above, provides an example. A closer examination of the characteristics of the demand loads in the areas of York Region most in need of capacity increases might indicate specific parts of the customer base on which CDM expenditures could bring large results. A possible example is the large role of electric space heating demand in the area north of Newmarket, which is in Hydro One's service territory. (As noted in Appendix B2, Newmarket Hydro has recognized the opportunity represented by electric heating in its service territory.) Reducing the heating component of demand could be a worthwhile item in the portfolio of remedies for the overall needs in York Region. Closer study may turn up other possibilities of this sort. This leads us to make the following recommendation.

Recommendation 7: A focused study of the potential for electricity savings in York Region in order to identify specific 'high-yield options' should be undertaken.

Concluding Comments

In sum, we view the conservation activities of the utilities operating in York Region as being off to a good start. Those actions, of course, need to be monitored closely, which can be expected, as the framework for electricity CDM activities being developed by the OEB takes form and is applied. We reiterate also that if long-term CDM impacts are to be realized, the utilities need further guidance on what is expected of them in the longer term and that this will depend on clear policies and leadership from the Government and the Conservation Bureau.

2.4 Assessment of Demand Response Programs: Experience Elsewhere, Potential Impact & Recommendations

The demand response aspects of Conservation & Demand Management programs are attractive conceptually and are the types of programs that many would like to see succeed in the energy marketplace. Certainly, some CDM programs have been well designed and researched prior to implementation and effectively launched. However, as already noted, there is some disagreement over the magnitudes of electricity savings that can be attributed to the programs.

> "Advocates of electricity restructuring have argued that it would increase the efficiency of electricity production and consumption. In many cases, the results so far have fallen well short of this promise, with the California electricity crisis of 2000-01 being just the most publicized disappointment. While there has been heated debate about the reasons for these failings, there is remarkable agreement over at least the broad outline of one response: the demand side of the industry should play a more active role, receiving economic incentives to help balance supply and demand. The way in which this response should be implemented, however, is still the subject of a great deal of debate."
> Borenstein, Jaske and Rosenfeld (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. San Francisco: The Hewlett Foundation Energy Series.

Demand response programs (DRP) focus on the need to reduce electricity usage and, typically, on the hypothesis that demand is responsive to the price of electricity. Demand response programs have been used to some extent for many years. However, the need for more effective programs and for their more intensive and extensive use has been much more highly recognized during the past five years. Several jurisdictions have developed their demand response programs to such an extent that dependable programs are available for reducing electricity usage overall and, especially, during periods when system capacities are in danger of being overwhelmed. New York State, California and Pennsylvania/New Jersey/Maryland have most intensely investigated DRPs and have implemented programs that have helped to better manage the electricity network within those jurisdictions. While the IESO has a demand response program (TDRP), there seem to be only four participants as of June 17, 2005 (http://www.ieso.ca/imoweb/market/participants.asp)

Demand response programs typically rely on the sensitivity of electricity usage to price variations. There is a variety of demand response programs and each expects that higher prices will result in lower demand or overall usage by some types of customers and lower prices will precipitate shifting of electricity usage from higher price periods to lower price intervals. Other DRPs directly pay customers to curtail some or all of the electricity usage during high demand periods that could result in emergencies. Some of those payment DRPs are voluntary in that customers decide whether in fact they will curtail usage when asked; others demand that subscribed customers curtail when asked and financially penalize those that do not comply.

The 2005 Annual Report of the New York Independent System Operator (NYISO) explicitly includes the potential from their Special Case Resources program in calculating the projected system surplus over supply for the summer 2005 season. (See Exhibit 2.4.1)

The fact that surpluses are projected for New York City and Long Island are very positive outcomes of the NYISO demand response programs.

Exhibit 2.4.1 The Impact of the NYISO Special Case Resources Program

New York Load & Reserve Requirements vs. Available Supply – Summer 2005				
Region	Requirement (Load + reserve or locational requirement)	Generation Available	SCRs* Summer 2005	Projected Surplus above Requirement Summer 2005
NY State	37,715	38,340	897	+1,522
NY City	9,052	9,224	158	+330
Long Island	5,179	5,329	90	+240
**SCR's are a Demand Response Program that can reduce customer demand on peak load days.*				

Demand Replacement Programs

Demand replacement programs are usually designed to move some of a customer's load off of the grid and onto the customer's generators. Large commercial and industrial customers are the most common participants in these programs. While these programs can have some effect on the overall network demand, those results depend on the customers' generating costs and the incentives that are provided by the LDC or some other market participant. The success of backup generating solutions depends closely on the degree to which the environment might be affected by the use of the generating alternatives.

Backup generators can have the advantages of providing a predictable level of load reduction if they are regularly maintained and tested. For well-managed systems, the change-over to backup generation can be very quick with little affect on the normal operations of the organization. In addition, the capital costs have already been covered for systems currently in place. For some organizations, backup generation is required by law and for others it is a necessity of prudent business operations. In one study[26], it was estimated that backup generation accounts for 20% to 25% of potential load reduction. In order to facilitate participation of backup generation in load reduction programs, creative approaches to satisfying environmental concerns are often necessary.

The most common participation by residential customers is through fuel replacement programs and these usually involve moving customers to depend more on natural gas and renewable energy sources and less on electricity.

[26] Goodman, Charles A., Grayson Heffner and Galen Barbose (February 2002). Customer Load Participation in Wholesale Markets: Summer 2001 Results, Lessons Learned and "Best Practices", Ernest Orlando Lawrence Berkeley National Laboratory.

York Region programs. There seems to be little in the way of demand replacement programs operating in York Region. PowerStream has a pilot backup generation program.

Recommended investigation of demand replacement programs. Information obtained by the study team indicates that there might be a winter peaking profile in the Armitage area. Other information seems to confirm that summer peaking profiles exist in Newmarket and towns south of Newmarket. If this information is correct, there are likely to be areas within the area served by Armitage within York Region, i.e., Hydro One territory, that are not yet served adequately with natural gas or are served with natural gas but have not converted their main heating equipment to natural gas. This seems to be an opportunity to replace primary dependence on electricity for heating with more efficient natural gas alternatives.

Recommendation 8: We recommend that the OPA encourage the research and development of demand replacement programs for York Region.

Peak Load Reduction Programs (Long Term Programs)

Peak load reduction programs are motivated by demand for electricity threatening to exceed capacity, at least during some time periods and in some locations. The plan is to displace new capital investments with reductions in peak load demand over extended periods of time and, perhaps, permanently. A key element in the design of peak load reduction programs is to move the risk of exposure to high prices from the provider to the customers as electricity rates move toward market prices, i.e., higher prices during peak load periods.

The principal operating mechanism of peak load reduction programs is the substitution elasticity of peak and off-peak power of some segments of customers. There is a range of pricing programs that can be offered to industrial, commercial and residential customers. The authors of this report have been involved in researching the feasibility of price responsive load management programs in several jurisdictions.

Portfolios of pricing products include two or more of the following rates:

1) **Current or Standard Rate.** Naturally, the current or standard rate might vary from jurisdiction to jurisdiction. In many cases the standard rate includes and energy charge per kWh, a demand charge per kW and a monthly customer charge.

The Standard Plan

3.0¢/kWh for the energy charge

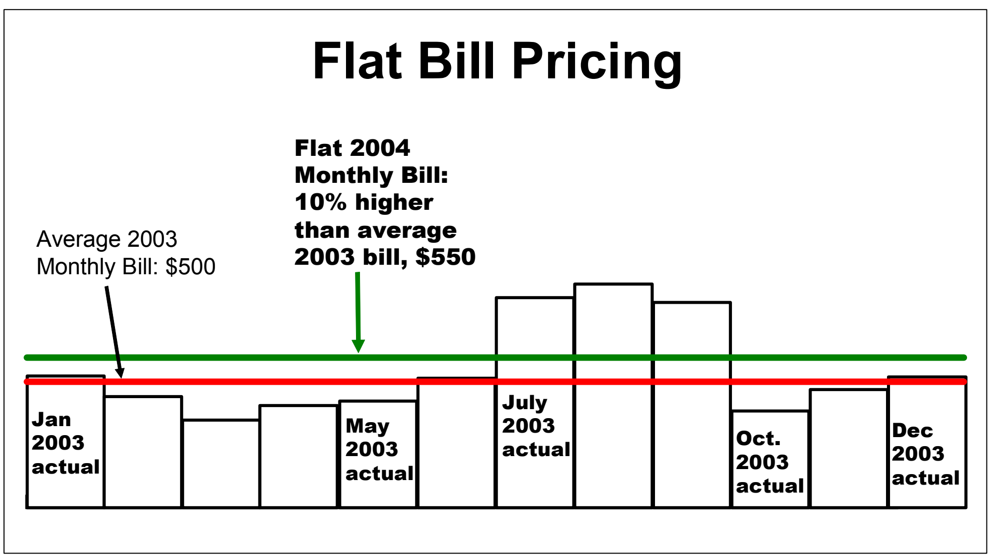
$15/kW for the demand charge

Plus

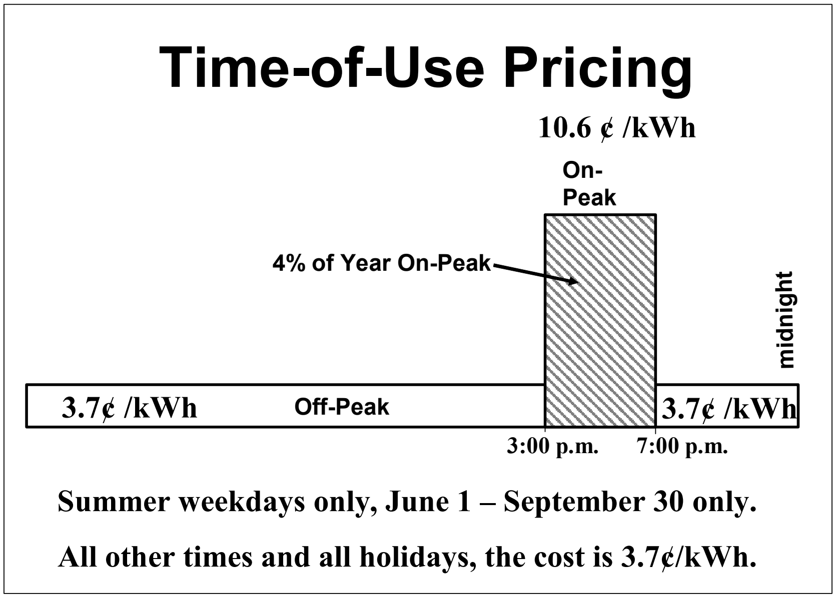
$20.00 Monthly service charge

2) **Energy Only**. This rate is the simplest as perceived by the customer in that it is simply a price per kWh with no demand charge or any other fee. While Energy Only is the easiest to understand, it is typically the most expensive rate.

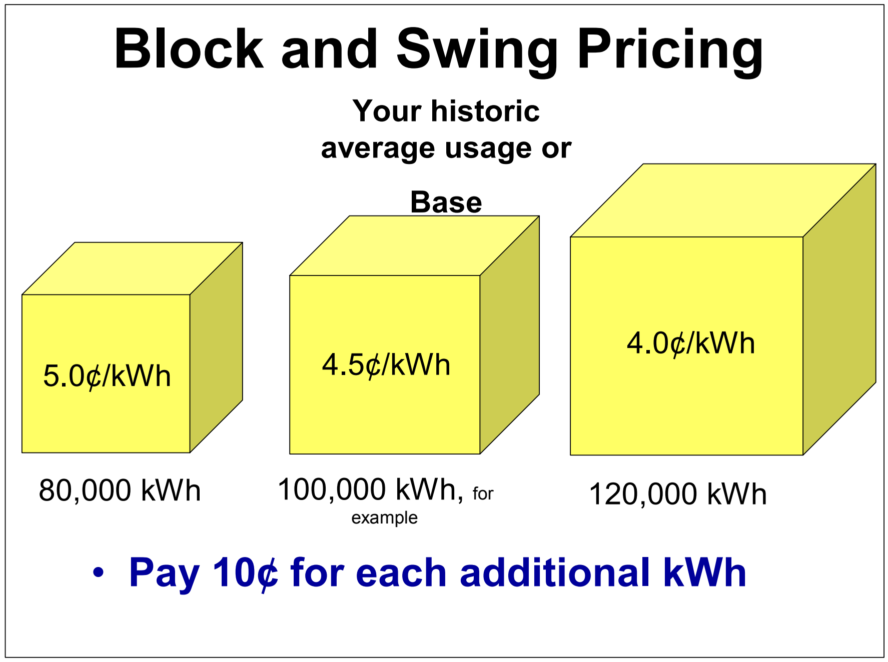
3) **Flat Rate.** The customer's average monthly bill from the previous year is calculated, a premium of, e.g., 10%, is added and the customer is charged that amount each month for the next year or so, depending on the contract.



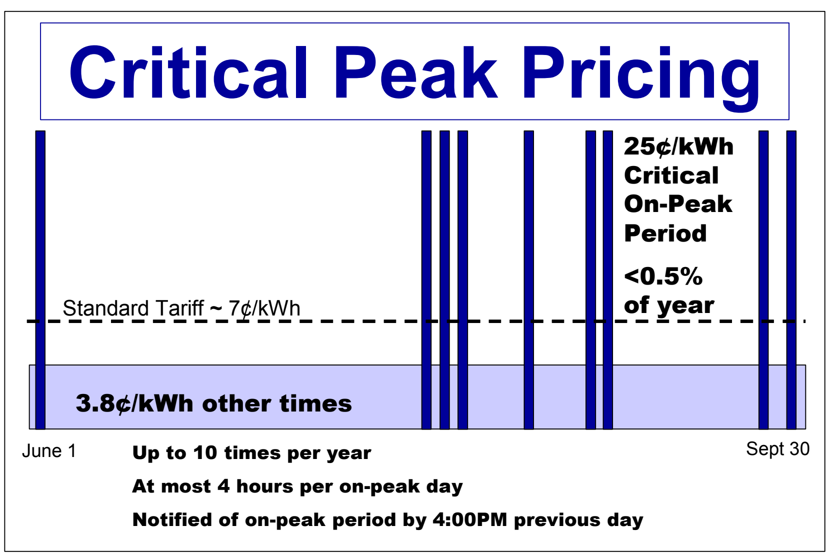
4) **Time-of-Use**. This rate charges customers a premium price for electricity during a pre-specified block of time during the day. The higher on-peak price during the peak period is intended to motivate customers to shift their loads to off-peak periods. The width of the peak time block during the day, the on-peak and off-peak prices and the possibility of a shoulder peak period should be based on customer research and LDC needs. The higher peak period prices are normally in effect only for the summer season in summer peaking jurisdictions.



5) **Block & Swing.** The customer's historical monthly usage is calculated to be their base block in a Block & Swing rate. Customers are provided with the choice to buy a block of electricity for the month equal to their base block at a constant price per kWh, a block 20% larger than the base or 20% smaller than the base block. If they were to contract for the base block and then use more than the base block amount during the month, they would pay a substantially higher price per kWh for all additional usage. As insurance, customers are given the opportunity to buy a larger block, often 20% larger than their base, for a price per kWh lower than the base block rate. If they decided to buy a block 20% smaller than their base block, the cost per kWh would be somewhat higher than the cost for the base block. If the monthly usage is less than the contracted block, there is no refund for the unused amount.

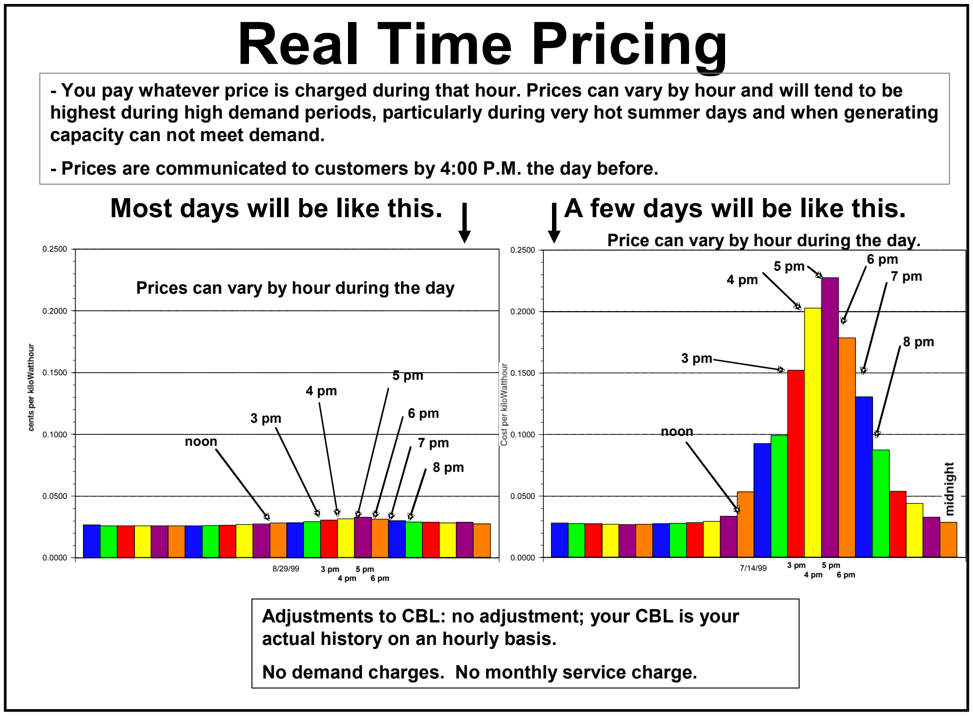


6) **Critical Peak Pricing.** CPP is a fairly complex rate for many customers to understand. This rate is normally in force during the summer season for summer peaking jurisdictions. During that period there is a base off-peak price set that is substantially below the standard tariff. Customers agree to be exposed to substantially higher rates during several days per year. For example, customers might be exposed to the higher rates during at most 10 days per year. The customer is notified by some pre-set time the day before a high peak exposure is expected to occur. On the day of the exposure, the customer will be subject to the higher rate for a pre-specified period of time. There are no monthly service or demand fees. CPP is somewhat like an intermittent TOU rate with very high peak prices.



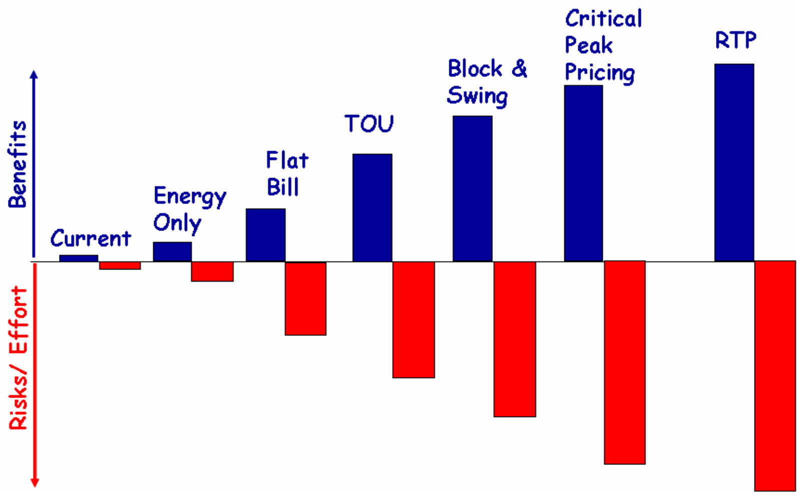
7) **Real time pricing.** The risk of being exposed to very high hourly prices is greatest under RTP rates, and the potential for experiencing the lowest average

costs are typically maximized. RTP rates vary by the hour and the hourly prices are communicated to customers at least one hour ahead and in some jurisdictions the prices are sent to customers by a specified time during the previous day. Usually no service or demand charges apply. In some rates, the RTP prices does not apply to all usage during an hour but may be based above the customer base load (CBL).



The two most commonly used long term peak load reduction programs are time-of-use (TOU) and real time pricing (RTP) programs. Pricing products move from a position of minimal risk and minimal marginal reward, usually the customer's current rate, to rates that are perceived as having very high risk but can produce the maximal reward if followed. Exhibit 2.4.2 shows a very full portfolio of pricing products that include the current program, an energy only rate, a flat rate, time-of-use, block & swing, critical peak pricing and real time pricing. The sequence of risk and reward may change between segments and programs depending on the prices and other parameters of the rates. However, the sequence shown in Exhibit 2.4.2 has been observed in studies conducted by one of the authors.

Exhibit 2.4.2 The Relationship between Risk and Return in Pricing Products



Deal, Ken (2005). "Comments about integrated CDM programs", McMaster Institute for Energy Studies: May 2005 Conference.

The introduction of new pricing products intended for demand management must be based on adequate customer research that reflects the principles of the diffusion of innovations. Those principles are:

1) Most markets are comprised of heterogeneous segments of customers, each of which might have very different preferences from those of other segments;
2) most customers do not readily accept change;
3) a small percentage of customers are innovators who will quickly accept change;
4) the diffusion of new pricing products will be successively accepted by those who tend to be more risk averse; and
5) those who are most risk averse will accept the innovation last.

Some key learnings from studies of electricity pricing products[27] include the following:

1) customers are most interested in those rates that provide cost benefits and reflect the way in which they use electricity or want to use electricity;
2) familiar pricing products win over new products initially, even when more expensive;
3) simple products, even when more expensive, will be most preferred by some segments, typically those who are most risk averse;
4) customers will try new products when the perceived benefits justify the risk;
5) it is very important to encourage customers to try a new pricing product and this is done by reducing the perceived risk, sometimes through contracts that guarantee no higher first year savings under the new rate;
6) encourage customers to re-subscribe to their first new pricing product and to eventually move on to riskier products that can offer further benefits; and
7) customers are motivated to conserve electricity by lower monthly bills, not by lower prices per kiloWatt hour.

[27] Deal, Ken (November 2004). How do you get the demand side to respond? McMaster Institute for Energy Studies Conference, McMaster University.

The successful design and marketing of new pricing products should be based on thorough understanding of customer preferences for the attributes of the rates within the proposed portfolio of products. Designing rates based on the needs of the provider without considering the customer leads to unfulfilled opportunities; customers react for their own reasons and not simply because it is best for the electricity provider.

Very few evaluations have been conducted to establish the substitution elasticity and the demand reduction due to non-standard rates. One of these studies estimated the average substitution elasticity over all types of customers to be 0.14, whereas the range was from 0 for customers in one specific category, to 0.11 for large industrial customers, 0.30 for government/education customers to 0.40 for industrial customers who were enrolled in an emergency demand response program in New York State during those EDRP events. The authors of that report[28] state that "Subjecting customers to default RTP without ensuring the availability of diverse and fairly priced alternatives would likely be a harder sell." Customers should be gently introduced to new pricing products and carefully encouraged to experience more risky options after being successful with safer and simpler initial offerings.

When introducing new pricing products, it is important for customers to feel as though they have choices and are not being forced into high risk products that have unproven benefits to them. The authors of the RTP study also state, "The experience in New York has shown that retailers may not offer adequate hedging options, so policymakers implementing RTP should ensure that such opportunities exist so that customers can choose the level of risk exposure they are comfortable with." In addition, they conclude that study with, "In summary, the NMPC experience shows that default RTP for large customers does deliver modest demand response, even when some customers seek to hedge against price volatility. Better dissemination of enabling technologies and customer education regarding response strategies would probably improve DR beyond that observed for SC-3A customers, yet to achieve socially optimal levels of DR at critical times, RTP is best implemented as part of a portfolio of DR options."

York Region programs. There are no programs for York Region that explicitly indicate intentions to research, test or launch peak load reduction programs. Of indirect consequence are the plans to install smart meters in each jurisdiction and eventually throughout Ontario. Smart meters by themselves might or might not result in changes in energy behavior; that remains to be seen. However, the Ontario Energy Board is designing rate changes to be imposed on those customers who have smart meters. There appear to be no valid estimates of direct energy or demand impact of smart meters.

Recommended Investigation of Long Term Peak Load Reduction Programs. The development and implementation of portfolios of new ways to buy electricity will be vital to shifting loads out of peak periods and into off-peak periods. Smart meters on their own

[28] Goldman, C., N. Hopper, O. Sezgen, M. Moezzi, R. Bharvirkar, B. Neenan, D. Pratt, P. Cappers and R. Boisvert (August 2004). "Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff". Ernest Orlando Lawrence Berkeley National Laboratory.

will not have nearly as much of an affect on changing energy usage behavior, if any, as will the combination of new pricing products with the smart meters.

The introduction and diffusion of new pricing products must be carefully planned and implemented. Customers, and especially residential customers, should be respectfully educated on electricity pricing and how to use new pricing products and smart meters to manage electricity usage in order to minimize their monthly electricity bills. An abrupt introduction of rates that challenge customers' adaptability to change could introduce long lasting reticence for other pricing initiatives.

There are valid ways to research pricing products and, better, portfolios of pricing products. Lessons from other jurisdictions should be relied on to guide rate changes in York Region and Ontario. Education of customers to the benefits of new pricing products is essential to the success of portfolio planning.

Recommendation 9: It is strongly recommended that the OPA supports research into the development and launch of a portfolio of pricing products for the York Region.

Peak Load Reduction Programs (Short Term Programs)

Short term peak load reduction programs commonly involve scheduled or unscheduled requests to large commercial/industrial customers to curtail their usage during emergency or planned high demand or low supply periods. These programs are of two types, contingency and market programs. While both types of programs pay customers for load reductions, market programs are voluntary from the standpoint of having no ability to enforce compliance and contingency programs impose financial penalties if promised reductions do not materialize. As shown in Exhibit 2.4.3 contingency programs have motivated substantially higher compliance than have market programs.

Exhibit 2.4.3 Performance of Contingency and Market Programs (Curtailment)

Table 3: Average Performance Characteristics of Contingency and Market Programs with Curtailment Events in 2001

Program Type	Number of Programs	Average Potential Curtailment Load (MW)	Actual Average Curtailed Load (MW)	Actual/Potential
Contingency	8	158	84	62%
Market	10	204	21	17%

Goldman, Heffner and Barbose, Lawrence Berkeley National Laboratory (2002)

Key lessons learned, or hypothesized, about short term peak load reduction programs:

1) proper marketing of demand response programs is essential for their success;
2) too many programs offered in a jurisdiction can lead to confusion among customers resulting in low subscription rates;
3) some segments of customers will react very differently from others … programs need to be tailored to each target market;

4) market programs (payment but no penalty) attract greater enrollment but have lower compliance rates than do contingency programs (payment plus penalty);
5) low enrollment rates among some sectors need to be researched to identify ways to increase enrollment and participation rates;
6) programs should be investigated to encourage participation of mid-sized commercial and industrial customers that could curtail even 100 kW, perhaps as low as 50 kW, without increasing administrative burdens; aggregation is usually relied on at this level;
7) incentives should be considered for installing interval meters with two-way communication capabilities, especially for mid-sized commercial and industrial customers and, possibly, for smaller C/I customers;
8) other enabling technologies for facilitating participation should be investigated; and
9) participation depends on the weather and on the wholesale price being high enough to motivate sufficiently high payments for curtailment; minimum wholesale prices seem to be $50/mWh but Locational-based Marginal Pricing can vary substantially within a jurisdiction as it does in New York State.

The New York State Independent System Operator (NYISO) has been recognized often as having been in the forefront of developing effective demand response programs. ISO-New England, PJM (Pennsylvania, New Jersey and Maryland) and CAISO (California Independent System Operator) have developed demand response programs as well. Within PJM, Baltimore Gas & Electric (BGE) has developed a set of demand response programs that seem to have been effective in garnering a fair level of customer participation. Many of those programs rely on published day-ahead prices at which customers might sell their load. Some of the programs require notification from customers while others require customers to specify the strike wholesale price above which they have preauthorized part of their load to be sold back. BGE has identified 122 mW of potential demand reduction under their several programs.

Commonwealth Edison has also been recognized for their demand response program development and implementation. Commonwealth Edison programs attracted 3,000 participants for a total potential load reduction of 540 mW and drawing from small to very large customers. In 2001, demand response programs appear to have motivated reductions of 480 mW; backup generation seems to have been a key enabler. Portland General Electric measured load reductions of 162 mW over 122 daily events from July 2000 to May 2001. Experience for all providers is that low wholesale prices reduce participation.

Exhibit 2.4.4 Northeast US Contributions of DRP Programs

Table 2: Summer 2001 Contributions of Price-Responsive Load and Other DSM Programs

ISO	System Peak (MW)	Interruptible Load	Curtailable Load	Other DSM	Total DSM	DSM as % of System Peak
PJM	52,977	2,000	70	-	2,070	3.9%
NY ISO	29,983	-	500	365	865	2.9%
ISO NE	25,675	-	65	1,522	1,587	6.2%

Goldman, Heffner and Barbose, Lawrence Berkeley National Laboratory (2002)

One of the best time periods for understanding potential DRP contributions was the week of August 4, 2001 in the northeast US. As shown in Exhibit 2.4.4 and as referenced by Goldman, et al, "price-responsive load and other programs reduced system peak demands by 3-6% and helped avert potential system emergencies". It was estimated that the NYISO Emergency Demand Response Program provided reliability benefits of between \$870,000 and \$3,484,000 for a single hour of operation in August 2001. The U.S. Department of Energy estimates emergency DR resources will provide \$340,105,172 nationally in benefits for 2005 under a scenario similar to August 2001 when reserve shortages were critical and wholesale prices were high.[29]

While involved parties have struggled with arguments such as whether payments to participating DR customers are subsidies, whether DR participants receive "double payments" and whether DR programs can be "gamed", it is generally acknowledged now that demand response programs are a worthwhile venture and have the potential to avert emergencies and to motivate behavioral changes of the long run.

York Region programs. It appears that short term peak load reduction programs have been considered only for very marginal introduction in the York Region.

Recommended investigation of Short Term Peak Load Reduction Programs. Peak load reduction programs (short term) are increasingly being seen as part of the mix of demand management programs needed to take pressure away from having to build new generating plants and transmission solutions. While these programs can be developed for York Region, it would be more efficient to develop such programs for Ontario.

Recommendation 10: It is highly recommended that the OPA encourage serious consideration of short term peak load reduction programs for York Region.

Likely Effects of CDM Programs

The following table summarizes information obtained from published sources regarding the effect of CDM programs in other jurisdictions. While each of the cited programs is different, savings achieved in other jurisdictions provide a basis for understanding the potential impact of CDM programs in York Region.

[29] Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design, U.S. Department of Energy, April 20, 2003.

Examples of Published Estimates of the Likely Effects of Demand-Side Management and Demand Response Programs

Conservation and Demand Management Program	Published Potential Effects on Demand based on Evaluation
Instantaneous feedback of meter information	- 38 UK feedback studies: reductions up to 20%, median approx. 10%[a] - 14 US daily feedback programs: 11% average reduction[b] - up to 20% reduction in Woodstock, Ontario study
Time-of-use meters[c]	- about 13% reduction in peak demand in summer with a 4-to-1 price differential (noon-5pm) - winter effects smaller - changing price ratios and peak-price intervals changes the impacts
Load Control[d]	Limited interruptions per month of air conditioning & water heating -2%
Mass market programs (education & promotion) - refrigerator example[e]	Sales-weighted average energy used by new refrigerators in Canada fell by 38% between 1990 and 1997
Energy audits/ retrofits – example: NRCan's EnerGuide for Houses[f]	Reduced energy consumption 20-38% in post-retrofit homes in 2003-2004
Backup Generation	20% to 25% of possible reduction • 12% in market programs • 31% in contingency programs
Price responsive load reduction programs	3% to 6% reduction of system peaks during emergencies

[a] Sarah Darby, *Making it Obvious: Designing Feedback Into Energy Consumption* (Environmental Change Institute, University of Oxford, 2000).
[b] C. King & D. Delurey, "Twins, Siblings, Or Cousins? Analyzing the Conservation Effects of Demand Response Programs", *Public Utilities Fortnightly*, Mar, 2005.
[c]D.C. Mountain, "Assessing Time-of-Use Electricity Rates", *Energy Studies Review*, V.5, No.3.
[d]Pilot study in Newmarket area in progress
[e]Natural Resources Canada study, as reported in International Energy Agency, *Cool Appliances, Policy Strategies for Energy-Efficient Homes* (2003), p.92.
[f]Natural Resources Canada, *Improving Energy in Canada,* Report to Parliament Under the *Energy Efficiency Act* For the Fiscal Year 2003–2004, p. 19.

APPENDICES

Appendix A: Review of the Hemson Report

Comments on: Hemson Consulting Ltd.,

The Growth Outlook for the Greater Golden Horseshoe, January 2005.

Hemson Consulting Ltd. was commissioned, apparently by the Greater Golden Horseshoe Forecast Committee, to prepare forecasts of population, employment, and housing growth at the regional/county level within the Greater Golden Horseshoe area. Since these forecasts are key elements in the load forecasts made by several of the electric utility companies and system operators, it is important to review how they were prepared. Our particular interest here is on the forecasts for the York Region.

It is worth noting at the outset that the Committee consisted of "staff from the Ministries of Public Infrastructure Renewal, Transportation and Municipal Affairs and Housing, as well as staff of upper tier and single tier municipalities" (Foreword, p.1), that the "forecasts and report were prepared with the assistance of the GTAH[30] Forecast Committee... and the Outer Ring Advisory Committee" (Executive Summary, p.i), "both of which had extensive opportunity for review and comment" (p.1) on the report.

The document itself is well prepared. While it provides only a verbal description rather than a precise mathematical statement of how the forecasts were made, the procedures that have been followed are clearly presented, and appear to be reasonable.

The following comments relate only to the GTAH forecasts and, within the GTAH, to the forecasts for the York Region.

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30 GTAH stands for Greater Toronto Area - Hamilton

Population forecasts are at the heart of the report. A standard cohort-survival model was used, in which the GTAH population of the initial period is moved ahead to 2031, based on assumptions relating to births, mortality, and migration. (Presumably initial values are drawn from the 2001 Census, but that is not made explicit; adjustments are made for population 'undercount' in some but not all of the forecasts.) Whether the projections are made year-by-year or in five-year jumps is not clear; some forecast results show five-year population age groups. Fertility rates are held constant at 2001 levels and mortality rates are assumed to continue to decline in accordance with long-term trends (p.20).

Population forecasts are more sensitive to assumptions about migration the smaller the geographic area of interest; in small geographic areas migration can dominate other sources of change in the population. ('Migration', in this context, includes immigration from abroad, movers from other provinces, and movers within the province.)

Annual immigration at the national level is assumed to decline from 218,000 per year in 2001-06 to "just under 210,000" per year from 2006 to 2031, and Ontario's share is assumed to decline from 56% to 54% (p.20). The Greater Golden Horseshoe (GGH) region is expected to be overwhelmingly the main destination for immigrants; after allowing for emigration (whose assumed level appears not to be specified), *net* annual international migration into the GGH is forecast to decline from 94,000 in 2001-11 to 82,000 in 2021-31, and almost all of it to go to the GTAH (p.21). While it is the assumed destination of almost all net international immigrants, the GTAH is projected to gain only 3,000 per year through *net inter-provincial migration* (the observed rates averaged 10,000 annually in the period 1981-91 and 3,000 in 1991-01; p.21) and to lose through *net intra-provincial migration* (the average annual losses were 16,000 in 1981-91 and

15,000 in 1991-01; they are assumed to rise from 19,000 per year in 2001-11 to 27,000 in 2021-31; p.21).

In the report the GTAH is treated as “a single urban area ... The distribution of future growth is, therefore, more a matter of where growth is directed through planning and the ability of sub-markets within the urban area to accommodate different types of housing and employment” (p.6).

Three ‘reference’ forecasts were prepared for each of six areas (York being one of them) within the GTAH, based on trends in housing described as ‘current trends’, ‘compact’, and ‘more compact’. The three differ in terms of the market share associated with single and semi-detached housing units, on the one hand, and row housing and apartments, on the other. The ‘current trends’ forecast assumes that 52% of new housing will be single or semi-detached; for the ‘compact’ forecast that proportion drops to 46%, and for the ‘more compact’ forecast to 39%. ‘Current trends’ would result in more population in York Region (and other areas outside Toronto), while the other two forecasts would result in less population in York Region (and more in Toronto, Hamilton, and Durham).

In addition, ‘high’ and ‘low’ forecasts are presented; they assume a continuation of ‘current trends’ in housing and differ from the ‘reference’ case only in terms of the overall migration assumptions. For the GTAH the ‘reference’ annual migration averages for the decades 2001-11, 2011-21, and 2021-31 are 74,000, 58,000, and 55,000. The ‘low’ forecast involves assumed reductions from reference levels of 6,000, 18,000, and 32,000 per year; for the ‘high’ forecast the increases are 9,000, 25,000, and 23,000 per year. Clearly this is a considerable range.

Employment forecasts are tied to the population forecasts, taking into account participation rates and allowing for commuting and unemployment. Age-specific participation rates are applied to the population of each sex and the results summed to forecast the labour force (pp.23-24). It is not stated whether the rates are specific to the GTAH (in which case they might be drawn from the Census) or are province-wide rates (drawn from either the Labour Force Survey or the Census). In any event, near constant rates are projected for those under 25, increasing rates for women over 40, and moderately increasing rates for older age groups. A constant unemployment rate of about 6% is assumed, and used to calculate employment.

Our overall judgment is that the Hemson forecasts are competently done and seem reasonable.

Appendix B: Existing DSM Programs in York Region as well as Federal and Provincial Programs

Michael Agrell

Appendix B1: Details of Some Federal, Provincial, Local and Other Initiatives

Federal

Federal initiatives these days are largely driven by the need to met Canada's Kyoto commitments, and their programs, such as the One-Tonne Challenge, are thus primarily aimed at reducing atmospheric emissions through conservation measures. Some of their programs are described in the following sections. The programs are run by the Office of Energy Efficiency (OEE) that is part of Natural Resources Canada. They are organized on a sector basis, and some of their programs in the residential, commercial and industrial sectors are described below. Further details can be found on the NRC web site at: NRC Portal

Residential Sector programs

In the residential sector there is a wide range of programs including Energuide for Houses, Appliances, and Heating and Cooling equipment, EnergyStar, R-2000, and the One-Tonne Challenge.

When you decide to upgrade your home using EnerGuide for New Houses advice, your builder works with a technical report from an independent EnerGuide for New Houses energy advisor to produce a cost effective, energy efficient house.

Major electrical household appliances and room air conditioners sold in Canada must meet minimum energy efficiency standards and are required to display an EnerGuide label. Information on the EnerGuide label is the result of extensive testing, based on Canadian Standards Association (CSA) test procedures. The EnerGuide energy consumption rating is an average measure of how much energy individual appliances typically consume when used at different temperature and/or speed settings.

The EnerGuide Heating, Ventilating and Air Conditioning (HVAC) Energy Efficiency Rating System provides consumers with all the information needed to purchase energy-efficient home heating and air conditioning products and provides contractors with the tools to increase sales

The international ENERGY STAR® symbol is a simple way for consumers to identify products that are among the most energy-efficient on the market. Only manufacturers and retailers whose products meet the ENERGY STAR criteria can label their products with this symbol. In 2001, EnerGuide teamed up with ENERGY STAR to help consumers find the most energy efficient refrigerators, dishwashers, clothes washers and room air conditioners on the market. An appliance receives the ENERGY STAR rating if it is significantly more energy efficient than the minimum government standards, as determined by standard testing procedures. The amount by which an appliance must exceed the minimum standards is different for each product rated, and depends on available technology.

Developed in partnership with Canada's residential construction industry, the R2000 program aims to promote the use of cost-effective energy-efficient building practices and technologies. Since being introduced over 20 years ago, the R-2000 Standard has set the benchmark for home building in Canada. The Standard is continually upgraded to include new technologies as they become established in the marketplace, and it's flexible enough to apply to any type of home.

The One-Tonne Challenge asks you to reduce your annual greenhouse gas (GHG) emissions by one tonne. (about 20%). Registered participants will get updates and tips on actions they can try. Further information on the challenge can be found at: Climate Change

Commercial and Institutional Buildings

The Model National Energy Code of Canada for Buildings 1997 (MNECB) contains cost-effective minimum requirements for energy efficiency in new buildings. The MNECB applies to all buildings, other than houses of three storeys or less, and to additions of more than 10 m^2 to such buildings. The MNECB provides maximum thermal transmittance (1/RSI or U) levels for building envelope components per type of energy (oil, natural gas, electricity, wood, propane) for different regions of Canada. These levels were determined using regional construction and heating energy costs in a life-cycle cost analysis. As well, the MNECB gives regional U-values for windows, references energy-efficient equipment standards, and identifies when heat recovery from ventilation exhaust is required for dwelling units.

To allow flexibility in achieving a minimum level of energy efficiency, the code offers three compliance approaches a Prescriptive path, a trade-off path, and a performance path. The MNECB was prepared under the auspices of the Canadian Commission on Building and Fire Codes and was first published in 1997 by the National Research Council Canada (NRC). The NRC, Natural Resources Canada, the Canadian Electricity Association, and the provincial and territorial government ministries of energy funded the research in support of the development of the model code requirements and the supporting software.

Industrial

Natural Resources Canada has programs for the industrial sector in the following areas, financial assistance, technical information, regulations and standards, leadership and networking opportunities, and training and awareness

Financial programs include:

- Industrial Energy Audit Incentive
  Helps defray the cost of hiring a professional energy auditor to conduct an on-site audit.
- Financial Assistance for Process Integration
  Assists in the hiring qualified consultants to conduct a process integration studies.
- Industrial Building Incentive Program (IBIP)
  This demonstration initiative, provides funding of up to $80,000 for eligible organizations based on process and building savings. Organizations must first join the Industrial Energy Innovators
- Tax Incentives
  Take advantage of tax incentives for investments in mechanical systems that generate electricity and/or produce heat.
- Renewable Energy
  The Renewable Energy Deployment Initiative (REDI) funds solar heating and biomass systems.
- Research and Development
  The CANMET Energy Technology Centre - Ottawa (CETC-Ottawa) works with industry, trade and professional associations, utilities, universities, and other levels of government to develop and deploy leading-edge technologies in the areas of residential, commercial and industrial energy efficiency and alternative, renewable and transportation energy technologies. CETC-Ottawa provides leadership in its energy-related technology areas through its repayable and cost-shared contract funding programs.

  CETC-Ottawa's offices wholly or in part administer the following funding programs:

  - Bioenergy Development Program
  - Buildings Group Contribution Funding
  - Canadian Initiative for International Technology Transfer
  - Canadian Transportation Fuel Cell Alliance
  - Emerging Technologies Program
  - Industry Energy Research and Development
  - Renewable Energy Technologies Program
  - Transportation Energy Technologies Program

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Information about the NRC's activities with respect to provision of technical information, regulations and standards, leadership and networking opportunities, and training and awareness, can be found at NRCAN Industrial

Ontario

Ontario's programs, while having an environmental underpinning, seem to be largely driven by the looming shortfall in electricity capacity. The Province is in the initial phase of its declared aim of moving towards a Culture of Conservation. In May of this year it presented the report of Conservation Action team which recommended 30 specific initiatives that will help build a conservation culture in Ontario.

As well as setting up some of the institutional framework, and has moved to improve efficiency standards.

Energy efficiency standards

In February of this year (2005) the provincial government announced that it is moving forward with new energy efficiency standards that would increase the minimum efficiency level of air conditioners by 30% and eliminate production of approximately 50% of the least efficient models currently available in Ontario.

The regulation sets efficiency standards for three new products:

- Large residential gas-fired furnaces
- Street and industrial lighting ballasts
- Refrigerator display cabinets.

The regulation also proposes EnerGuide labeling for gas fireplaces, as well as new, tougher efficiency standards for seven products already covered under the act:

- Residential and commercial central air conditioners/heat pumps
- Packaged terminal air conditioners and heat pumps
- Commercial and industrial unitary air conditioners
- Heat pumps and air-conditioning condensing units
- Water-loop heat pumps used to heat and cool commercial buildings
- Residential electric water heaters
- Clothes washers.

The draft regulation would only affect the production of new products after set compliance dates, and would not affect any equipment in current use or on retailers' shelves.

These code changes will have to be factored into any new load forecast.

The Provincial government has also given the electric distribution companies money for conservation and demand management programs. This initiative is described in the following section.

Another body encouraging conservation in Ontario is the Toronto Region Conservation Authority (www.trca.on.ca/corporate_info/). The Conservation Authority encourages sustainable communities by facilitating broad community understanding, dialogue and action toward integrated approaches to sustainable living and city building that improves the quality of life for residents, businesses and nature.

Other

Other bodies operating across the country, and active in Ontario are the Federation of Canadian Municipalities (FCM), and The Canada Green Building Council (CGBC). The FCM has been the national voice of municipal government since 1901. FCM is dedicated to improving the quality of life in all communities by promoting strong, effective and accountable municipal government. They are sponsors of the Centre for Sustainable Community Development and of InfraGuide. Details are given at their web site: FCM.

The Canada Green Building Council has been only recently formed. Its mandate is to accelerate the design and construction of Green Buildings across Canada. The Council is a broad-based inclusive coalition of representatives from different segments of the design and building industry

The Council will work to:

- change industry standards,
- develop best design practices and guidelines;
- advocate for green buildings, and
- develop educational tools to support its members in implementing sustainable design and construction practices

CGBC's key initiative is its Leadership in Energy and Design (LEED) program that encourages sustainable building practices by registering and certification process. *(??? Add more detail from there presentation?)* There are 4 levels of certification of buildings, basic, silver, gold, and platinum. For new buildings there are 2 compliance demonstration methods, requiring either minimum reduction compared to a reference design building of either 25% if based on MNECB, or 18 % reduction if based on ASHREA (www.ashrae.org) standards. Further details can be found on there web site at: http://www.cagbc.ca/

The Natural Gas companies (Union and Enbridge) also deliver conservation programs to their customers. Those of Enbridge are described below. They are organized by sector

Residential

Enbridge provides advice and information to its residential customers on how to save money, and to make the home more comfortable and efficient. It provides tips on such matters as: saving hot water, stopping air leaks, and upgrading of furnaces. As well participation in the EnerGuide house evaluation service is incented through the offer of a free programmable thermostat. Details of these and other parts of their residential offering can be found at http://www.cgc.enbridge.com/A/hub_residential.asp

Industrial (see download summary)

Enbridge Gas distribution is working to assist its industrial customers with a variety of ways. It has energy efficiency incentives in the areas of energy monitoring and targeting, industrial HVAC, Steam savings. It also has a program for the operators of Greenhouses. Enbridge also provides advice on energy management, including encouraging its customers to have energy audits performed. Details of these activities can be found on the Enbridge web site at: http://www.cgc.enbridge.com/B/hub_industrial.asp

Business

For the business sector Enbridge has incentive programs and partner programs. The incentive programs include the MultiCHOICE program that incents such items as:

- Higher efficiency boilers
- Higher efficiency combination water and space heating systems
- Controls, including Building Energy Management Systems
- Building envelope upgrades , including Windows & window film, Air sealing measures, and Insulation improvements above R-12
- Water conservation measures such as low flow showerheads and faucet aerators and horizontal-axis washing machines

Better Buildings Partnership program (BBP)

The Better Buildings Partnership Program responds to the challenge of global warming by promoting and implementing energy-efficient retrofits. The program is delivered in the partnership with Enbridge are The City Of Toronto, Toronto Atmospheric Fund, Toronto Hydro and various Energy Management Firms (EMFs).

Commercial Building Incentive Program

Natural Resources Canada Commercial Building Incentive Program (CBIP) (see above) offers builders of new commercial, institutional and multi-residential buildings grants equal to two times their annual energy savings, up to $60,000 per building for the incorporation of energy efficiency features. Eligibility for this program is determined through an energy simulation using NRCan-approved software. The approved building design must be at least 25% more energy-efficient than if constructed to the Model Energy Code for Buildings (MNECB). Enbridge provides assistance with the expense of conducting an energy simulation through its Design Advisory Program (DAP).

Design Assistance Program

Enbridge Gas Distribution's Design Assistance Program (DAP) has been created to encourage a design process that considers energy and environmental efficiency from the beginning. It offers qualified proponents a fixed DAP incentive of

$4,000 to undertake design activities aimed at improving a building's energy and environmental performance - whether it is a new building, an addition to an existing building or a major renovation.

More details of these activities can be found on Enbridge's web site at: http://www.cgc.enbridge.com/B/hub_business.asp

Appendix B2: Details of Programs by Utility

Note: the difference in level of detail provided is, in part, a reflection of the different levels of information provided in the Distribution Companies plans.

Aurora

Smart Meters

Smart meter pilot

The success of 'smart' meter technology in Ontario depends not only on installations, but on a behavioral shift in how residential customers respond to price signals and are motivated to conserve energy. A smart meter pilot program will enable Aurora Hydro to test the effectiveness of price signals and gain experience in helping residential customers leverage lasting value from smart meter technology. It will also provide a valuable observation point for Aurora Hydro to learn how best to address customer interests and concerns in implementing smart meter technology.

Envisioned is a pilot program of 330 smart meter installations and monitoring by utility staff or a third party service. It will help determine the most effective communication and web link technology needed to bring about effective customer involvement. The results of information and orientation to customers with these meters can later be compared to a similar neighbourhood without smart meters to determine the potential gains in energy and load reduction.

Customer Education

Cold water washing pilot

Aligned with an ongoing program of the Energy Efficiency Alliance, Aurora Hydro will promote the use of cold water clothes washing in the residential sector. With an estimated consumption of some 200 kWh of energy for washing clothes with electrically heated water each month in a typical family home, there is ample opportunity to reduce both energy and load – some coincident with peak demand.

The campaign will make use of information and advertising currently available from the Energy Efficiency Alliance, for insertion in customer billing envelopes, and on the Aurora Hydro website.

Estimated funding allocation $1,500
Target: Residential customers
Key measures: Insertion of flyer to one residential billing cycle

In School Education

School speaker program

Students are a vitally important audience for shifting consumer behaviour over the long term. Curricula in most schools currently provide environmental studies, even in junior grades. As such, it is possible to extend this environmental content with additional messages and information about electricity conservation, and how it helps so many stakeholders in society. Aurora Hydro proposes to fund the acquisition of content and suitable speakers to visit schools and participate in environmental studies by instructing students on the basics of how the electricity system works, and how the choices they make have significant impact on it. Content and materials would be made available to the Board of Education to integrate into existing environmental curricula, and to distribute materials for students to retain. Years two and three may include contests for energy efficiency ideas from students.

Estimated funding allocation: $10,000
Target: 20 schools
Key measures: Attendance at speaker event

General Service Education

Key account seminars

Direct interaction with major commercial and industrial customers is the most effective medium for transferring conservation and demand management information and receiving valuable feedback. In addition to the ongoing contact with key accounts by Aurora Hydro representatives, a series of seminars is proposed to provide useful information about available programs and technologies that helps customers benefit from improved energy efficiency. Envisioned as breakfast meetings that do not inconvenience business schedules, the forums will allow the exchange of information and ideas, as well as a feedback point for programming.

Facilitate conservation and demand management program access

One of the systemic barriers to practical conservation and demand management in all sectors is a lack of knowledge or understanding of the various energy efficiency incentives available federally, provincially or regionally. Aurora Hydro proposes to help facilitate the reach of programs and program incentives to various customer segments through the use of its website, and key account contacts.

Low Income Projects

Low-income conservation and demand management pilot

Aurora currently has some **266** units of low-income housing, including both house and apartment units. Utility costs can be particularly difficult for lower income families because rent and food expenditures often consume most of a household budget. By helping fund the improvement of energy efficiency in lower income housing, it is possible to provide families with more control over their electricity bills.

Aurora Hydro proposes that it provide funding or grants to existing social service programs such as “Share the Warmth” to help families upgrade the energy efficiency of their homes. This funding would provide materials and services such as insulation, weather stripping, window replacements and other measures that help improve the energy envelope of a dwelling.

Energy Efficient Appliance Program

Residential air conditioner upgrade pilot

The sale of window air conditioner units has burgeoned in recent years, as have central air conditioning installations. However, window air conditioning units can remain in service for more than a decade, and frequently longer than 20 years, implying that there are a large number of lower efficiency units still functioning. Aurora Hydro believes that by supporting the purchase of upgraded window air conditioners, and the safe recycling of retired units, both peak load and environmental impacts can be reduced. This support will be in the form of cash-off coupons for the purchase of Energy Star and other highly-rated air conditioning units through major retailers. Aurora Hydro will also provide support to the recycling chain that currently handles Aurora’s disposal of old appliances.

Energy Audits

Big box retailer retrofit pilot

The fastest growing segment of the retail commercial sector is the ‘Big Box’ store, where retailers construct large floor areas to sustain large volume sales. However, such structures are typically constructed with a focus on building construction cost efficiency, rather than energy efficiency. As a consequence, retailers are not deriving the full operating efficiency that they otherwise might attain through more energy efficient technologies and practices. Aurora Hydro proposes that an audit program be piloted to provide big box retailers with detailed information on how they can upgrade the energy efficiency of their operations with investments that deliver a payback period of 3 years or less from energy savings. Such a pilot program would provide an energy audit and report by an accredited firm to participating retailers approved for audit by Aurora Hydro. Then can monitor implementation with monitoring and reporting.

Power Factor Corrections

Low power factors for major industrial or commercial customers can have adverse impacts on distribution system losses. With some 67 customers with power factors less than 90%, Aurora Hydro believes an opportunity is at hand to quantify the impacts of poor power factors and identify lasting solutions that contribute to loss reductions and a more efficient distribution system overall. This will provide a plan for future implementation of power factor corrections in conjunction with customers.

Design Consulting

To promote more energy efficient design in commercial and industrial buildings, Aurora Hydro, will provide professionals to review the designs of pending construction in Aurora to offer design improvement suggestions that will enhance energy efficiency. This service and the findings will be promoted through municipal level planning linkages and other forums.

Air conditioner upgrade pilot

Similar to the residential sector, there is a growing body of older less efficient window and wall air conditioners used in the commercial sector. A pilot program will help encourage businesses to trade in their older units in exchange for credits or coupons for the purchase of more efficient units. Traded models will then be properly recycled.

Commercial Motor Efficiencies

There is a growing base of large manufacturing customers in Aurora, representing demand levels that exceed of 300 kW. Aurora Hydro proposes the issuance of grants on a pilot basis to help fund the replacement of energy intensive technologies in manufacturing facilities with more efficient alternatives, and measure the demand and energy impacts. Such grants would help pay for the cost of new motors, lighting and HVAC.

Municipal Leadership Programs

Town of Aurora demonstration program

Aurora's municipal structures currently number 33 offices, works, recreation and pumping facilities, 20 schools and 18 sets of traffic lights. Aurora Hydro proposes arranging energy audits for these facilities, and recommending energy efficiency improvements that the Town can select to showcase. These might include insulation upgrades, lighting and HVAC improvements; and the introduction of solar technologies that can help defray energy load and costs. Aurora Hydro would arrange to meter consumption patterns for these improvements to provide demonstration data for interested businesses and municipalities.

Festive lights pilot

Seasonal lighting represents a load that is largely borne during peak evening hours. A pilot program is proposed to promote the purchase and use of low-energy LED lights by residential and business customers. As part of this pilot, all Town seasonal lighting will be changed to LED lighting for demonstration purposes. Additionally, Aurora Hydro will co-sponsor local retail promotions of LED lighting through funding and distribution of discount coupons for lighting during the billing cycle, and through multi-municipal or provincial programs to trade in older festive lighting for high efficiency LED lighting. Funding will also be provided to the Town of Aurora's annual festive lighting contest, to reward the best energy-efficient display.

Research and Development Distribution System Optimization

Loss mitigation study

The first step in lowering system losses is to analyze the distribution system to quantify losses and the potential for mitigation. Such a study would model the Aurora Hydro distribution system in areas of higher load for system configuration, loading patterns and customer factors to quantify losses and identify opportunities to mitigate those losses. The findings, if appropriate, would form the basis for a loss mitigation pilot as described below.

Loss mitigation pilot

Concurrent with the quantification of system losses and the prioritization of loss mitigation opportunities, it will be possible to pilot test the loss reductions from a transformer upgrade, and from other interventions such as the installation of capacitor banks, reconductoring, and other improvements. The measured results of this pilot can then be the basis for a decision to undertake further retrofits for additional loss reduction.

Newmarket

URB Gateway Pilot Project (complete)

This Energy Management Pilot Program offered by Olameter provides customers with existing broadband service links to their thermostat, an interval electric meter and back office systems via the Internet to provide customers with energy management capabilities and information. Goals of this project were to prove that the technology and infrastructure exists to control loads in *residential and small commercial facilities;* manage the control of HV AC loads in a near real time manner; manage residential loads with minimal effect on participants' lifestyles or business operations; show that giving customers access to data over the web helps them to understand and manage their energy use. Olameter is implementing this technology with Itron, a world leader in AMR technology.

Building Partnerships

NHL is working with two energy efficiency service management firms that offer a comprehensive 'package' of professional services that enhance comfort, increase energy efficiency, reduce everyday (operating) costs, and include financial support packages. NHL will work with these firms, and others, and help with building relationships within all sectors of the community. These companies offer "one stop shop" programs and NHL has signed a Memorandum of Understanding with these firms. These firms will offer incentives, as approved by NHL, to our customers to encourage their participation. Incentives such as, and not limited to, paying a portion of audits or providing financial assistance for the projects (business, commercial; industrial and **especially social** housing). All projects will be audited to determine the efficiencies achieved.

Residential

Working with Homeworks, a home services company offering a complete one stop shop range of home energy efficiency and comfort services including audits, retrofits, financing and quality assurance. Newmarket is actively working with Homeworks to develop a marketing plan for our community. Homeworks have created an energy audit specific to electricity consumption that will be subsidized by NHL. We have engaged a number of residential customers and conducted Focus Group sessions to determine the initial energy audit and programs to offer to our customers. Program offerings will be modified, if necessary, to accommodate the needs of our residential customers based on successes. We are now preparing to host workshops for our residential customers to introduce Homeworks to our community and provide tips on how energy efficiency can be achieved. We want to provide a range of programs to suit the diverse community we serve. NHL services about two thousand five hundred residential customers who have electric heating. Homeworks is working with other energy providers to insure our residential customers are aware of any/all programs that are available to encourage conservation and energy efficiency in their homes. NHL is also considering a variety of programs independent of the services provided by Homeworks.

Affordable / Social housing

NHL has successfully engaged this sector in our service area. Representatives from NHL and Homeworks met recently with the Property Managers of all social housing providers in Newmarket i.e. York Housing Inc., non-profits, Provincial co-ops, Federal coops, and supportive housing. Opening remarks for the meeting from Newmarket Mayor Tom Taylor, who is Chair of York Region Community Services and Housing Committee, included comments on the importance of working together and active participation in NHL's plan. York Region Community Services and Housing staff and a representative from the Social Housing Services Corporation ('SHSC') were also in attendance. There was very open dialogue and from that Homeworks has created a questionnaire which will be completed by all housing providers. The completed questionnaire will provide detailed information as to the type of units, size, type of heating, age of building etc. NHL is providing space on our website to help in maintaining open and accessible dialogue and updates. Following the completion of the questionnaires this group has resolved to meet again to form a Steering Committee which will be a working group to determine next steps. SHSC will be attending these Steering Committee meetings and it is hoped other energy and services providers will ultimately participate. It is our intention to channel the enthusiasm of these housing providers into creating workable solutions to assist their clients so they can afford their energy bills and become a community of conservationists. The OEB allowed development expenses *of* up to *$25,000.00* to be charged against the third installment of market adjusted revenue requirement, for the research of technologies or programs that could be employed for conservation or demand management activities. This sum will be applied to this sector to provide consulting services to the Steering Committee to ensure all partnerships are leveraged and all available programs and funding through other sources is considered. It is realized the Property Managers will be required to obtain approval from their Board of Directors and the steering Committee will work closely with them to help them achieve their goals

It should be noted, NHL will be selectively deploying smart meters to measure program results tenant behaviour at no cost under their Smart Meter Pilot

Small Business

Working towards a partnership solution which will provide a self-audit tool for small business or a web based self-audit tool for our small business customers. The small business sector is a very hard to reach group as most small businesses rent or lease space and are not willing to spend dollars to retrofit locations they do not own. Once we have chosen the desired format, our small business customers will be notified. The completed audit will be analyzed and customers will receive a comprehensive report detailing their consumption and where energy savings may be achieved and may also provide recommended solutions. Weatherization kits and compact fluorescent lights may be included as part of the package. NHL continues to meet with its small business customers and discuss possible offerings with other energy and. services firms to determine what other programs we might offer to help these customers reduce their energy consumption. The initial offering will include an education component about how savings with minimal dollar investments can be achieved. NHL is actively working with the local Chamber of Commerce to communicate with and assist small business.

Business/Commercial/Industrial.

NHL is working with Ecosystem, an independent energy management company with a strong background in electromechanical engineering experience.
Ecosystem provides a no cost analysis of building mechanical systems and energy consumption test for project feasibility and if required, a project plan will be prepared which may include but not limited to the supervision and coordination of the construction and they will monitor energy consumption post implementation until estimated savings are met. Ecosystem brings a holistic approach tailored to meet the customer's financial objectives and energy performance targets. NHL will work to develop complimentary programs to encourage participation with Ecosystem. Our results in this sector will focus on total company productivity and dollars savings as well as overall energy use. Already, Ecosystem is providing analyses to many key users and NHL will continue to work with Ecosystem and our business/commercial/industrial sectors to achieve energy savings and efficiencies. Ecosystem has successfully engaged with several of our Commercial and Industrial customers. We are not able to provide details of proposed programs and implementation due to confidentiality agreements with customers. NHL is

confident Ecosystem will deliver on the energy performance targets set out in these agreements.

Energy Education Program

This is a key component for this project to be successful. Some of the educational components include and are not limited to:

- Attending Council Ward meetings to speak about energy conservation and DSM programs available.
- Setting up a Conservation hotline
- Involving students in energy conservation projects and providing incentives to participate
- Meeting and addressing all sectors including local Council meetings and Chamber of Commerce events
- Meeting with major energy consumers
- Creating opportunities to meet with customers to determine the best way to assist them with their energy concerns
- Program to assist customers in understanding how to use their interval meters to help them reduce their energy costs
- Customer DSM Portal on the NHL website - customers setup profiles of their homes/businesses to assist them with determining how they consume "energy and how they can reduce consumption. The portal will be expected to interface with NHL's Smart Meter technology to provide 'real time consumption information to our customers
- Newsletter dedicated to energy saving programs and activities
- Hosting NRCan workshops to introduce customers to programs available

Additional Potential Programs/Discretionary Expenses

- Subsidize Municipal appliance pick up charges to encourage replacement of old appliances.[31]
- Modify NHL’s existing Interactive Voice response System to add an Energy Conservation Hotline with energy efficiency quick tips and direct links to the plan partners

[31] In the first quarter of this year Newmarket Hydro picked up a total of 244 appliances for a total kwh value of 2,500,000.

PowerStream (Markham, Richmond Hill. Vaughan)

Co-branded mass market program

This flagship co-branded mass-market program (e.g. *powerWISE*™) is a multifaceted approach to fostering the conservation culture in Ontario. Through development of a significant cooperative effort amongst six of the largest municipal Local Distribution Company's (LDCs), this program will become synonymous with specific initiatives such as Compact Fluorescent Lighting (CFL) change out programs, LED Christmas Lights, Energy Star, Multi-Choice, energy audits, water heater blanket wraps, school based education and a host of other programs aimed at providing customers with the tools and education needed to reduce their energy usage. Access to online services such as energy consumption calculators, an energy expert, and personalized energy audit services are contemplated as components of this program.

Target users
Mass-market including residential and small commercial

Benefits
Increased awareness, improved product supply, culture shift, and significant demand and energy reductions.

'Smart' meter pilot

A pilot program for residential SMART meters will be deployed to enable the assessment of metering, communications, settlement, load control and other technologies that may be used to accommodate the universal application of SMART meters in the future. Further, sub-metering opportunities for the purposes of customer information in a bulk-metered situation (i.e. condominiums) may be considered. This initiative will commence upon the release of a formal definition of a SMART meter by the Board.

Target users
Residential and small commercial customers.

Benefits
This program supports the Minister of Energy's commitment to the installation of 800,000 SMART meters across Ontario by 2007. It will provide PowerStream with the experience and knowledge needed to efficiently expand the use of SMART meters over the next several years.

In conjunction with appropriate rate structures, the program will also provide customers participating in the pilot programs with an incentive to conserve or shift energy use.

Smart Meter Program

LDC will make an investment to further the use of PowerStream SMART or interval meters by commercial industrial and institutional customers. This program will commence upon the release of a formal definition of a SMART meter by the Board.

Target users
Commercial, Industrial and Institutional customers

Benefits
This program supports the Minister of Energy's commitment to the installation of 800,000 SMART meters across Ontario by 2007. These meters are seen as an important means of establishing a 'conservation culture' in Ontario. In conjunction with appropriate rate structures, they will encourage customers to conserve or shift energy use.

Design advisory program

This initiative helps to create an integrated approach to the design process for new buildings, and involves architects, engineers, building owners and PowerStream design advisors. Through visits or by working through existing service advisors PowerStream will provide conservation information and make specific recommendations for energy savings.

Target users
Residential and small commercial customers

Benefits
This program results in cost effective improvements to the energy efficiency of a building without adversely affecting other performance requirements stipulated by the owner. More specifically, the Advisor can develop an energy performance model to demonstrate achievable energy savings and provide a breakdown of energy end uses. Through the installation of energy efficient equipment during construction, the customer benefits by avoiding stranded costs incurred with equipment upgrades.

Residential Load control

Load control uses a real time communications link to enable or disable customer loads at the discretion of the utility. These controls are usually engaged during system peak periods or when required to relieve pressure on the system grid and may include such "dispatchable" loads as electric hot water tanks, pool pumps, lighting, air conditioners, etc.

Target users

Direct load control applies to all market segments. Though the control systems and technologies may vary by market segment, the methodology remains the same.

Benefits
Load control allows customers to respond quickly to external price signals. This also provides a mechanism for utilities to relieve pressure on constrained areas within the distribution grid and also reduces the need to bring on large peaking generators.

Social housing program

Energy audits

A standard energy audit will be used to assist customers in reducing their loads. As well, a training program may be implemented to allow companies with a certified employee or outside consultants to perform the audit. Any crosslinkages with the residential audit project will be accessed where feasible. Strategic partnerships will be analyzed for incentives or other synergies. These audits could lead to retrofits. Existing audit/retrofit programs will be evaluated.

Target users
Large consumers over 50 kW including schools, large commercial facilities, institutional facilities, industrial, and municipal facilities like recreation centres, arenas, and libraries.

Benefits
Include increased awareness, skills development, benchmarking energy data, establishing best practices, fostering the conservation culture within this sector and significant reductions in demand and energy consumption.

Load management

Demand response

Load control uses a real time communications link to enable or disable customer loads at the discretion of the utility. These controls are usually engaged during system peak periods or when required to relieve pressure on the system grid.

Target Users

Larger commercial, industrial and institutional customers.

Benefit
Demand control provides lower costs and increased stability for customers and utilities.

Distribution loss reduction

The Distribution Loss Program is a broad network based initiative to drive greater efficiencies within the distribution grid. This program will identify opportunities for system enhancements. Next steps will be to complete the engineering analysis and feasibility studies. Projects will be prioritized, selected and implemented based on the most attractive investment to results ratio. Items to be addressed may include, but are not limited to:
Power Factor Correction - Under the Power Factor Correction initiative, a power factor assessment will be completed which will identify locations for the installation of power factor correction capacitor banks.
Voltage Conversion - Voltage upgrades can save up to 90% of the losses associated with a feeder as higher voltages and lower current results in lower losses. This study will ascertain the locations and value of voltage conversions. This program could also involve changing all the meters on a particular feeder to SMART Meters so that the exact losses can be determined.
Power System Load Balancing - This program is designed to ascertain where load shifting can occur within the grid to improve system efficiency, including the location of optimized "open points".
Voltage Profile Management - Changing voltage profiles at the distribution station level can result in a peak reduction at the controllable distribution stations. This is in addition to the IESO's voltage reduction program and will not interfere with the effectiveness of that program.
Line Loss Reductions - Replacement of conductors such as #6 AWG copper with #2 AWG aluminum can reduce line losses. An evaluation of where such opportunities exist may be undertaken. The results and available funding will determine which projects will proceed.
Transformer and Other Losses – Using infrared scans of transformers, this program will help to identify additional electricity losses including overloaded equipment. "Hot" transformers will be investigated further to determine operational improvement opportunities.

Target users
The results of this program will positively impact all of PowerStream's customers.

Benefits
Reduced electricity distribution system delivery losses will reduce system demand, relieve network capacity to accommodate growth, and reduce the

requirement for new generating capacity in the Province. Costs associated with distribution system delivery losses are recovered through electricity distribution charges. Reductions in these costs will therefore benefit all customers.

Load displacement program

Adding generation behind the customer's meter provides an excellent opportunity to displace load from the local distribution system's grid in a very effective manner. Load displacement technology, such as combined heat and power systems, provides increased power efficiency. This may include technology such as thermal storage systems. Combined with an existing or new district heating/cooling distribution system this technology contributes to the development of sustainable energy networks within Ontario's communities. Other technologies such as micro-turbines, wind, biomass fuels and solar provide additional options to meet the customer's needs. This initiative will facilitate the development and implementation of these opportunities. Financial incentives will be considered based on the project's viability. Development of educational and technology programs in conjunction with local colleges and universities may be considered. Small pilots or demonstration projects to promote alternative and renewable energy sources may also be considered.

Target users
Commercial, industrial, and residential, schools, colleges and universities

Benefits
Benefits include additional capacity within the grid. Cleaner technologies result in reductions in green house gas (GHG) emissions. Other benefits include improved system reliability, reduced harmonics, back-up power possibilities, education and skills development.

Hydro One

Load management Programs

Smart metering

Install 240,000 meters by 2007, in all customers segments, in line with the OEBs working groups' recommendations. This includes all demand billed customers, and all new customers. Mass geographic deployment of 960,000 meters in the period 2008 – 2010 is planned.

Interval Metering Pilot

Install interval meters at approximately 130 new farm, commercial and industrial customers in the 200 to 500 KW demand range, allowing these customers to access their load profile data.

Time of Use Rate Pilot

For general service customers, offer rate incentives to shift electricity demand away fro periods of maximum demand and into off-peak periods.

Residential Load Control Pilot/Program

Targeted at residential customers with the air conditioning, pool pumps and hot water heating, for the installation of interval meters and control units. Newmarket is amongst the four areas selected as pilots for this program.

Commercial, Industrial and Farm Load Control Pilot/Program

No details given.

Conservation Programs

Low-income program residential

Hydro One Networks is currently in discussions with potential delivery channel partners. Content yet to be decided.

Residential Real Time Monitoring Pilot/Program

Provide homes with real time energy use monitors and feedback devices. Pilot underway.

Farm Energy Efficiency

Three program areas, compact fluorescent lights, Energy audit, and TVO information segments

Mass market (residential and small industrial & commercial customers)
Residential programs include: compact fluorescent lights. LED holiday lights, a self-administered energy analysis / audit program. An AC exchange program is also being investigated. Commercial and Industrial options, such as a customer efficiency Needs Analysis/Audit program, are still being investigated.

Communication and Education

Using POWERSAVER brand, increase awareness and understanding of customers, primarily residential and small business customers.

Distribution loss reduction

The Distribution Network Loss Reduction Program involves identifying and implementing projects in three specific areas where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses. The three areas in which opportunities for such projects will be investigated are:

- *Power Factor Correction*

  Feeder power factors in the distribution network are typically in the range of 0.85 to 0.95, depending on time of year, mix of customers, and customer usage patterns. Loss reductions in the order of 10 to 25% are theoretically achievable through power factor correction. Power factor correction is achieved through application of shunt capacitor banks on distribution feeders. Targeting feeders with the known poorest power factors will generate the highest contributions to loss reduction DSM.

- *Feeder Phase Balancing/System Configuration*

  The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. Preliminary studies indicate that, on average overall feeder loss savings in the order of 10 to 15% could be achieved through measures such as balancing phases and optimizing open point locations between feeders. Directing incremental funding toward these areas could result in overall economic benefits to customers.

- *Leveraging System Reinforcement Investments*

  Networks currently has an existing capital program for reinforcing its distribution network in response to load growth, for new customer connections, and for risk mitigation and reliability improvement. We generally assess programs based on technical and financial considerations using a least-cost planning approach. We will be amending our investment planning criteria to more explicitly identify and evaluate opportunities to reduce losses through plan modifications.