The Evolution of Residential Demand Response: From Program to Market

Phil Bosco, Independent Electricity System Operator, Toronto, ON
Kausar Ashraf, Independent Electricity System Operator, Toronto, ON
Brendan Callery, Independent Electricity System Operator, Toronto, ON
Humphrey Tse, Independent Electricity System Operator, Toronto, ON

ABSTRACT

The residential demand response market in the studied jurisdiction has evolved in the past 9 years for many reasons, such as system needs, technological advancement, and market maturity. The evolution of evaluation methods played a key role in informing policy decision that have now led to the inclusion of residential demand response resources in the next capacity auction.

The paper will describe the critical role evaluation played in the evolution of the program structure and how the capability to undertake evaluation in a market based environment has been created.

The paper will also describe how the development of an evaluation protocol, developed from repeated evaluations, replicated year after year led to the building of industry capability to structure it offering to the market in a way that allows for results to be verified and the value of the resource to be clearly identified.

The paper will review the methodologies and findings of previously published independent third-party evaluation reports and show the link from evaluation findings, to refinement of methods, and then changes in policy direction, which has ultimately led(?) to residential DR moving from a program based resource to being available in a capacity auction in December 2016.

Introduction

On May 31, 2004, the Minister of Energy granted approval to all electricity distributors (LDCs) in Ontario to apply to the Board for an increase in their 2005 rates by way of the third installment (“tranche”) of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in conservation and demand management (CDM) an equivalent of that amount. Consequently, in 2005 distributors brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR3.

This load control initiative was developed by Toronto Hydro, and named peaksaver®. Third tranche installations were performed until February of 2007. In 2007 Ontario initiated the province-wide deployment of the residential demand response program, and the Ontario Power Authority assumed control of the program’s funding.

As per R&SC DR program rules, system activations can occur between May and September but must not exceed four (4) hours in length per day to a maximum aggregate forty (40) hours for all system activations over the applicable months.

System activations are likely to occur on days where temperatures exceed 30°C. To maximize R&SC DR impacts, the program is being offered to consumers in areas of the province where the Local Distribution Company’s (LDC) demand is summer peaking, or in other LDC jurisdictions where unique circumstances exist.

The program is delivered to market primarily through participating LDCs who undertake localized marketing, facilitate participant enrolments and device installations (and installation reporting), fulfill the payment of participant financial incentives, and? provide ongoing participant support and device maintenance. The OPA will also undertake additional provincial marketing to compliment the LDC efforts.

Goals and Objectives

The goals and objectives of the R&SC DR program were to:

- Enhance the reliability of IESO controlled electricity grid by aggregating residential and small commercial central air-conditioning units and electric water heaters
- Increase awareness of the important role individual consumers have in reducing the province’s overall peak summer demand and the benefits of a reliable IESO controlled electricity grid

The Initial Evaluation

The initial evaluation of the residential demand response program was undertaken by Kema in the fall of 2009 and spring of 2010. The following describes the approach to the evaluation as documented in their published evaluation report.

Methods - Evaluation Plan Overview

The evaluation plan included the following elements:

- Review of existing residential demand response impact evaluations
- Assess and if feasible utilize 2008 residential demand response program participant smart meter data to complete an ex post analysis of program impacts
- Prepare a sampling frame and design sample stratification
- Field data collection

Load Data Modeling

The regression models that were used to estimate savings for this study are discussed in this section. The load modeling efforts for this evaluation took place sequentially. 2008 Smart Meter data was made available to KEMA in 2009. The first attempts to model OPA cooling load were on this household level, one hour interval data. During the summer of 2009, end use data were collected from a sample of participant households. These data, one-minute interval, AC compressor load data, supported a second kind of modeling – duty cycle modeling. This section starts with a discussion of the modeling process for the household Smart Meter data.

Linear Modeling with Household Smart Meter Data

This section describes the model specification utilized to obtain 2008 ex post load impacts for the peaksaver® program, based on Smart Meter data. The 2008 ex post load impact evaluation had two essential goals:

- Produce ex post estimates of load reduction that makes use of the premise-level SmartMeter meter data for program participants, and
- Produce an ex post model that will serve as a basis for ex ante estimates of load reduction.

Modeling Options

The goals of the 2008 ex post load impact evaluation motivated a focus on regression approaches that include event load reduction effects in the regression model. This approach's primary strength is the generation of ex ante results directly from the ex post models. With this general model specification in mind, KEMA explored three different modeling structures for the ex post impact evaluation:

- Individual premise level models – Each premise level is modeled individually and these individual results are aggregated to provide results at the LDC and customer type levels.
- Aggregate LDC/customer type models – Premise-level load is aggregated to residential or commercial groups by LDC. Regression models are fit to these aggregated data.
- Pooled models - A single model is constructed that includes individual premise data but which estimates average cooling and event effects.

All three of these modeling options use interval data from the summer months to estimate base load usage patterns, cooling load and peaksaver program event effects. To illustrate this process, we will refer to a plot of all August 2008 non-holiday weekdays, presented in Figure 1.

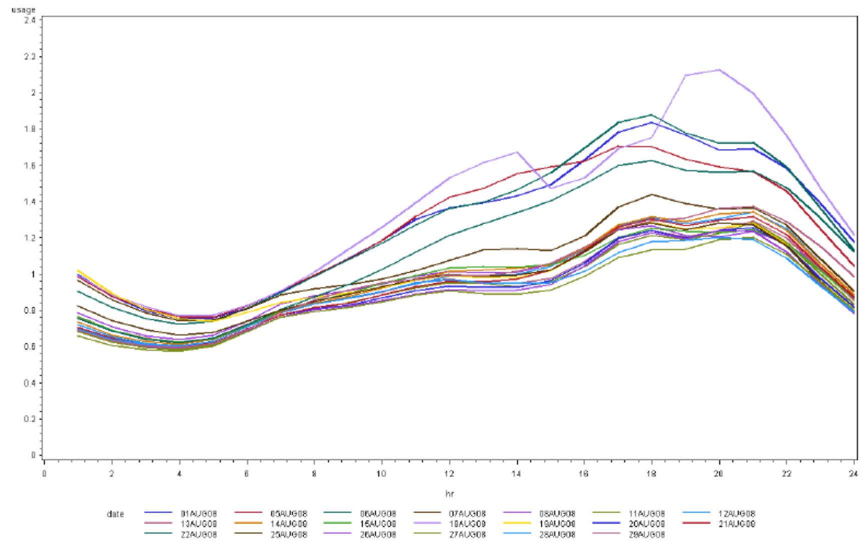

Figure 1. Toronto Hydro Residential Sector Daily Load Shapes, Non-Holiday Weekdays, August of 2008 Baseload

The base load portion of the load model is designed to characterize the general baseload shape. This part of the model describes normal usage of electricity that is not related to space conditioning (heating or cooling). The model describes an average daily shape with the option of shifts from month to month or due to day type. Characterizing the baseload shape is essential to characterizing the additional cooling load that occurs on hotter days.

Cooling Load.

The AC cooling load is informed by the subset of days where the outside temperature (or a combined temperature-humidity index) rises above some base temperature. This temperature level (degree day base) represents the outside temperature at which an individual (or the average) household generally starts using its AC. Cooling load generally increases as temperatures increase. Cooling load is more variable than the base load. Cooling usage is affected by all the factors that affect base load (schedules, occupancy, preferences) but also changing thermostat set-points, natural cooling (opening the windows), the thermal properties of the house, recent weather, etc.

Event Effects

The remaining part of the model is the event effects piece. Load impacts (event effects) are estimated only for the hours during which events took place. Event reduction is a function of AC cooling load (and all of its associated variation) and additional factors specific to the event control. Event load reduction is affected by the sizing of the unit as well as the usage patterns of the household. The adaptive algorithm in the switch mechanism injects the likelihood of changing load reduction as the number of events increases. In 2008, there were only five residential demand response events.

Basic Cooling Load Model

A basic cooling load model specification has three elements: an hourly base load effect, hourly cooling load effect and an hourly event effect.

This simple model can be estimated with a variety of different temperature variables. Temperature can be included in its hourly form or as a daily average interacted with an hour term. Humidity, another important driver in a climate like Ontario's, can also enter the model hourly or as a daily average. A common approach is to combine temperature and humidity into a single temperature-humidity index (THI). Akin to “feels like” temperature or heat indexes, THI reflects the different perception of heat at different levels of humidity. At the same dry bulb temperature, higher humidity will produce a higher THI than will a lower humidity. The implication is that humidity increases the likelihood that the AC will be in use at any given temperature.

2008 residential demand response Model Specification

The results reported for this evaluation are based on aggregate program population models. For each LDC and each type of customer (where that information was available) we created a single interval data series with average usage per hour.

Event Effects

The event effects portion of the model characterizes what happened on an event day that was different than an otherwise identical day. The cooling and base load parameters, estimated across all non-event days, provide the reference load within the model. The event effects, in combination, are the average differences from that reference load for each hour. The model estimates four hourly event effects which captures the load reduction resulting from the four hours of AC control. The model also captures the effect during the post event hours.

Duty Cycle Modeling with AC unit Logger Data

Duty cycle modeling is the load data modeling approach used for the 2009 impact evaluation. This approach uses end use data so does not face the challenge of separating baseload usage from cooling usage. This approach directly models cooling load. More specifically, this approach is based on the two key determinants of an air conditioner’s energy use: duty cycle and connected load.

- Duty cycle is the operating pattern of an air conditioner, usually described as a combination of the number of minutes on/off, and percent of the time period (usually an hour) that the unit operates.
- Connected load is the instantaneous demand (kW) of an air conditioner when it is on. Air conditioners are either on or off. For most units, connected load (kW drawn when the unit is on) varies slightly from one minute to the next, but is generally stable under similar weather conditions. Newer, multi-stage units can exhibit a wider range of connected load.

Estimating Expected Duty Cycle

The duty cycle component of the analysis consists of estimating the expected duty cycle under a range of times and conditions. Duty cycle is a function of cooling demand. Cooling demand is, in turn, a function of the difference between the actual and desired internal temperatures of the cooled space. Actual temperature reflects the heat building up in the house over the course of the day. The desired internal household temperature is completely determined by human behavior as indicated by thermostat set points. Hourly duty cycle will reflect the combination of these two factors.

Figure 2 illustrates the Tobit duty cycle model. The straight diagonal line represents the assumed underlying linear relationship between, in this case, expected unconstrained duty cycle and hourly temperature. The S-shaped curve shows how the model estimates the resulting constrained relationship between expected duty cycle and temperature. For any given temperature, the values on the S shaped curve indicates the expected duty cycle.

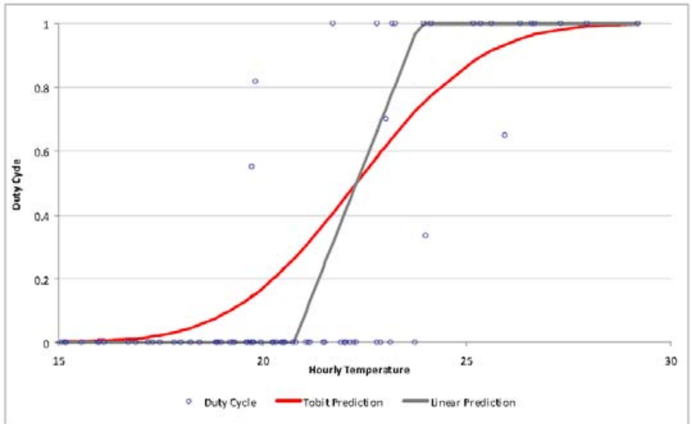

Figure 2. Duty Cycle Model Schematic

The actual model used is unit-specific, includes hourly indicator variables that allow the underlying linear trend to shift to reflect different set point behavior at different hours, and multiple temperature (and humidity) variables designed to mimic the thermals lags experienced by the house. The result is a complex model of unit-level AC usage that provides an estimate of expected duty cycle under any temperature conditions. Each expected duty cycle estimate is the percentage of connected load that would be used during that hour. Using either actual or estimated connected load, the expected duty cycle is transformed back to kW. These unit level results are aggregated to the program level using the weights from the sample design.

2012 The Change in Methodology – The Introduction of the RCT

The subsequent evaluation of the residential demand response program was undertaken by Freeman, Sullivan, & Company starting for the 2010 program year. The methodology was changed in the 2012 program year evaluation given the availability of smart meter data for virtually all participants. The following describes the approach to the evaluation as documented in their published evaluation report.

Ex Post Methodology

The *ex post* evaluation is based on a randomized control trial (RCT) in which customers are randomly assigned to several test groups, some of which are used as treatments in an experimental context and others of which act as controls. Analysis of the residential *demand response* population was conducted using 5 test groups of roughly 1,000 residential customers each chosen at random from each of the 6 LDCs who participated in the evaluation effort, except that only 3 test groups were chosen at Hydro One because, at the time, there were not a sufficient number of customers under contract to pull more samples.

Table 1 shows the total number of devices, by LDC, for which data was made available. Some LDCs did not provide interval data for all customers chosen for inclusion in the test groups. Except for Hydro One, all participating LDCs had provided interval data for an average of 800 customers in each of the 5 residential test groups. Hydro One provided interval data for an average of 400 customers in each of their 3 residential test groups.

LDC	Total Population of Devices	Total Number of Devices Included in Experiment	Number of Groups within LDC	Average Number of Customers Per Group
Enersource	9,786	3,462	5	692
Horizon	13,123	3,016	5	603
Hydro One	13,195	1,272	3	424
PowerStream	18,541	4,786	5	957
Toronto Hydro	67,958	4,403	5	881
Veridian	8,315	4,739	5	948
Total	130,918	21,678	-	-

Table 1. Residential Test Group Sizes

Table 2 shows how the residential test groups were actually called over the 2012 summer event period. On the system event-days, June 20 and July 6, only one group per LDC was designated as control. For reasons that are unclear, PowerStream load control devices did not appear to receive any EM&V event calls and did not have a control group for system wide event-days. On EM&V event-days, each treatment type (e.g., 50% cycling, 60% cycling, etc.) was assigned to a test group and other groups were assigned to control conditions (e.g., were not activated). Customer groups were rotated so that no one group was called for an excessive number of event-days.

(SC = simple cycling, C = control, R = ramping and True = True Cycling)

LDC Name	Assignment	Group Number						
		Jun 20 System 2-6 PM	Jun 21 EM&V 3-5 PM	Jun 29 EM&V 1-5 PM	Jul 4 EM&V 4-6 PM	Jul 6 System 2-6 PM	Jul 17 EM&V 3-5 PM	Aug 31 EM&V 3-5 PM
Enersource	50%SC	–	–	–	–	1,2,3	5	5
	60%SC	–	–	–	–	4	1	1
	C	–	–	–	–	5	2,3,4	2,3,4
Horizon	50%SC	–	5	–	2	3,4,5	3	5
	60%SC	–	1	–	3	1	4	1
	C	–	2,3,4	–	1,4,5	2	1,2,5	2,3,4
Hydro One	50%SC	3	–	2	3	1	2	–
	C	2*	–	1	2	3	1	–
	R	1	–	3	1	2	3	–
PowerStream	50%SC	1,2,3,4,5	–	–	–	1,2,3,4,5	–	–
Toronto Hydro	50%SC	–	1	–	3	4,5	4	1
	60%SC	5	5	–	2	1	3	5
	50%True	2	2	–	4	3	5	2
	C	1*	3,4	–	1,5	2	1,2	3,4
Veridian	50%SC	2,3,4	–	–	2	3,4,5	3	5
	60%SC	5	–	–	3	1	4	1
	C	1*	–	–	1,4,5	2	1,2,5	2,3,4

Table 2: Residential Test Group Assignments by Event-day and LDC

The residential test event protocol prescribed events to be called based on trigger conditions. System event-days are typically called if the Ontario system demand is predicted to be greater than 23,000 MW and the Ontario temperature is forecasted to be greater than 30°C. EM&V events are eligible to be called if the temperature in Ontario is forecasted to be greater than 30°C and if the day is not already chosen to be a system event-day. Discretion is given to the OPA to veto event-days even if conditions are met in order to accommodate customer comfort.

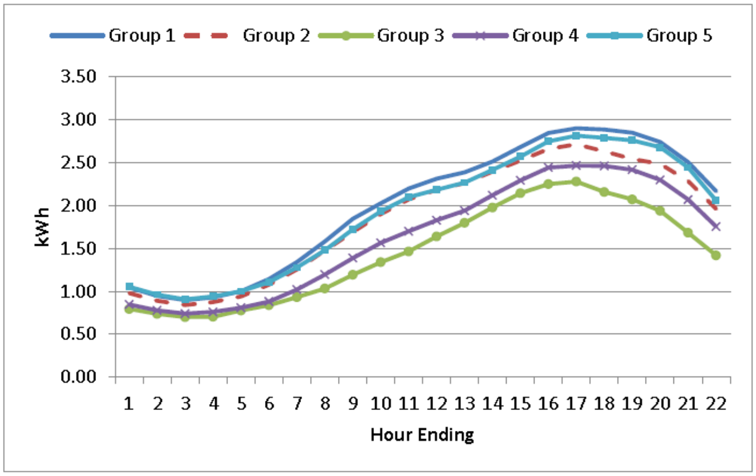

Figure 3. Veridian Control Groups Over All Event Days

Figure 3 shows an example of a comparability test across randomly selected groups in the Veridian LDC. Each line represents the load shape for a specific group over all events in which they were assigned to the control condition. Group composition did not change over the summer event period so each line represents a fixed group of customers and devices. For example, Group 4 acted as control on July 4 and August 31. The line labeled "Group 4" indicates the average load for this group on those two days. The magnitude varies for each line because the averages were calculated from different days, under different weather conditions and were subject to small discrepancies due to small samples and random chance.

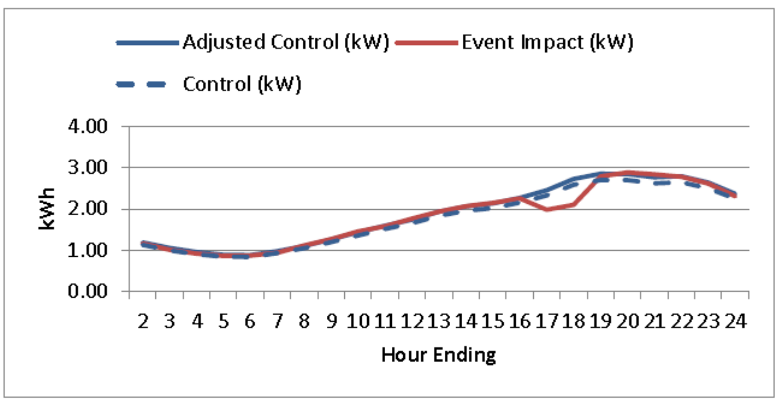

Figure 4. Same Day Adjustment Example

Unlike last year's evaluation that primarily focused on two LDCs and remained at the LDC level, this year's analysis was done at the zone level. Forward Sortation Area (FSA) was used to map customers into zones. Due to a lack of observations in certain zones, these zones were aggregated with other nearby zones to create larger analysis groups. Table 3 shows how zones were mapped into analysis groups.

Zone	Analysis Groups
East	N Ontario
Essa	
Georgian Bay	
Northeast	
Ottawa	
Southwest	
Long Point	LP Niagara
Niagara	
West	
South Central	South Central
Toronto	Toronto
Toronto Hydro	Toronto Hydro

Table 3. Relationship between Zones and Analysis Groups

Residential *Ex Post* Load Impact Estimates

Table 4 shows the average impact of 50% Simple Cycling per customer for each test event along with average temperatures over the event period for the residential *demand response* population. The values represent the average for all customers called for each event according to the testing regime summarized in Table 2. The specific groups called, and the LDCs serving these customers, vary across events and may explain some of the variation in estimated load impacts across events.

Type of Event	Event Date	Event Hours	Day of the Week	Average Reference Load (kW)	Average Event Impact (kW)	Average Percent Impact (%)	Average Temperature During Event (°C)
Whole Province	6/20/2012	2 PM-6 PM	Wednesday	2.50	0.44	18	33
	7/6/2012	2 PM-6 PM	Friday	2.47	0.44	18	32
	Average/Total	**n/a**		**2.48**	**0.44**	**18**	**32**
EM&V Test	6/21/2012	3 PM-5 PM	Thursday	2.46	0.44	18	28
	6/29/2012	1 PM-5 PM	Friday	2.20	0.34	16	30
	7/4/2012	4 PM-6 PM	Wednesday	2.54	0.48	19	32
	7/17/2012	3 PM-5 PM	Tuesday	2.61	0.44	17	33
	8/31/2012	3 PM-5 PM	Friday	1.87	0.27	14	30
	Average/Total	**n/a**		**2.33**	**0.40**	**17**	**31**
Total	**Overall Average/Total**	n/a		2.38	0.41	17	31

Table 4. Average Residential per Customer Reference Loads, Impacts and Temperatures on 2012 Event-days

Tables 5 and 6 show the average estimated impacts by LDC and event-day for both 50% and 60% simple cycling. Two things should be noted from these tables. First, as expected, the average impact under 60% cycling is larger than the average for 50% cycling. This is true for each LDC and is true on nearly all event-days. There are four cases where the average impact under 60% cycling is less than 50% cycling, shaded in grey in Table 6. However, the differences are small and almost certainly the result of relatively small sample sizes and random differences in treatment and control groups for some events. It is important not to read too much into small differences across events and LDCs, as the overall research design was intended primarily to produce accurate impacts on average event-days across the province.

Day	Estimated Impact (kW) for 50% SC											
	Enersource		Horizon		Hydro One		PowerStream		Toronto Hydro		Veridian	
	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temperature (°C)
20 Jun 15-18	--	–	--	--	0.40	32	0.47	33	0.51	34	0.41	34
21 Jun 16-17	--	–	0.26	30	--	--	–	--	0.48	28	–	--
29 Jun 14-17	--	–	--	--	0.36	30	–	--	--	--	–	--
4 Jul 17-18	--	–	0.33	30	0.50	30	–	--	0.55	32	0.47	32
6 Jul 15-18	0.40	33	0.33	31	0.48	32	0.49	32	0.45	33	0.41	33
17 Jul 16-17	0.49	34	0.27	33	0.53	31	–	--	0.50	34	0.51	34
31 Aug 16-17	0.31	30	0.26	27	--	--	–	--	0.34	30	0.31	30
Average	**0.40**	**33**	**0.27**	**30**	**0.46**	**31**	**0.42**	**32**	**0.46**	**32**	**0.42**	**33**

Table 5. *Ex Post* 50% Simple Cycling by Date and LDC

Day	Estimated Impact (kW) for 60% SC											
	Enersource		Horizon		Hydro One		PowerStream		Toronto Hydro		Veridian	
	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)	Event Impact (kW)	Temp (°C)
20 Jun 15-18	--	--	**--**	**--**	--	–	–	--	0.48	34	0.38	34
21 Jun 16-17	--	--	0.39	30	--	–	–	--	0.52	28	--	--
29 Jun 14-17	--	--	--	--	--	–	–	--	–	--	--	--
4 Jul 17-18	--	--	0.28	30	--	–	–	--	0.54	32	0.49	32
6 Jul 15-18	0.49	33	0.44	31	--	–	–	--	0.56	33	0.54	33
17 Jul 16-17	0.53	34	0.36	33	--	–	–	--	0.69	34	0.61	34
31 Aug 16-17	0.31	30	0.35	27	--	–	–	--	0.36	30	0.37	30
Average	**0.44**	**33**	**0.36**	**30**	**--**	**–**	**–**	**--**	**0.52**	**32**	**0.48**	**33**

Table 6. *Ex Post* 60% Simple Cycling by Date and LDC

Ex Ante Methodology

The *ex post* evaluation was done using an RCT research design that eliminated the need to develop and apply a predictive model to estimate *ex post* impacts as was done in prior years when regression modeling was used to develop reference loads and load impacts for *ex post* evaluation. This is a significant improvement in methodology since it eliminates any modeling inaccuracies from the ex post analysis. However, ex ante estimation requires development of a model that can predict impacts under specified weather conditions.

$$Impact_c = a + b \cdot mean9_c + \varepsilon_c$$

Variable	Description
$Impact_c$	Average per customer *ex post* load impact for each event-day from 4-5 PM
a	Estimated constant
b	Estimated parameter coefficient
$mean9_c$	Average temperature over the 9 hours ending at 5 PM
ε_c	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

Table 7: Description of CAC Load Regression Variables

Load impact measured for the hour from 4-5 PM was used as the dependent variable because, as discussed above, all test events covered that hour. An implicit assumption underlying this approach is that the load impact from 4-5 PM is the same (or at least very similar) regardless of the length of the event period leading up to that hour. Put another way, it assumes that the load impact from 4-5 PM is the same regardless of whether the event started at 2 PM, 3 PM or 4 PM. For programs similar to *residential demand response* in California, side-by-side testing done in 2011 and 2012 produced mixed results concerning whether load impacts at a given hour of the day vary systematically depending on the length of the event up until that time. Currently, there is no strong evidence of any systematic variation.

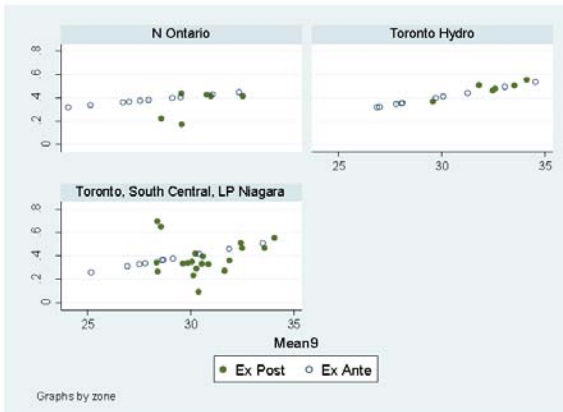

Figure 4. Ex Post and Ex Ante Impacts versus Mean9 by Analysis Group for 50% Simple Cycling

The advantage of this strategy for estimating impacts across all hours is that it forces load impacts across all hours to make sense with respect to each other. A common alternative in load impact evaluations is to model each hour completely independently. In cases with modest amounts of data or modest variation in observed conditions and impacts (as is frequently the case) this can lead to unreasonable results where, for example, the function that determines impacts from 4-5 PM is quite different from the function that determines impacts from 5-6 PM.

Residential Ex Ante Load Impact Estimates

Table 8 contains residential ex ante impact estimates for 50% simple cycling. The first set of rows show the average hourly per customer ex ante load impact estimate over the event period from 2-6 PM and the second set of rows shows the estimated hourly aggregate impact during a system wide event. The estimates are further categorized by monthly peak days and weather years.

Type of Estimate	Day Type	Extreme Year (1-in-10)	Normal Year (1-in-2)
Per CAC unit (kW)	May Peak Day	0.35	0.32
	June Peak Day	0.42	0.36
	July Peak Day	0.46	0.38
	August Peak Day	0.50	0.39
	September Peak Day	0.35	0.33
Whole-Province Aggregate (MW)	May Peak Day	62	55
	June Peak Day	74	62
	July Peak Day	80	66
	August Peak Day	87	69
	September Peak Day	61	57

Table 8. 2012 Residential Ex Ante Load Impact Estimates For 50% Simple Cycling by Weather Year and Day Type

The methodologies described above were operationalized for the OPA and known as the OPA Load Impact Protocols for use in future program evaluations.

A Change on Policy Direction – From Program to Market

On March 31, 2014, the government of Ontario issued policy direction to both the OPA and IESO that defined the future of demand response resources. The next framework of Conservation and Demand Management programs would no longer include programs for demand response. Going forward, to encourage further development of demand response in Ontario, the Independent Electricity System Operator ("IESO") will evolve existing demand response programs in Ontario and introduce new market based initiatives.

The IESO's Demand Response Working Group (DRWG) started a stakeholder engagement process to transition the programmatic demand response resources into the capacity auction. An initial signal was sent to the DRWG on September 30, 2016 looking for feedback getting residential demand responses resources to bid into the next auction, scheduled for December 2016.

The objective of the September 30 DRWG meeting was to implement an alternative baseline methodology to include residential DR participation for the 2016 Demand Response Auction. The session collected feedback in order to:

- To reduce unnecessary barriers for residential load to participate in demand response
- To measure with reasonable accuracy the delivery of demand response
- To balance administrative requirements of the design with the need to maintain auditability

The stakeholder feedback gathered before the meeting was as follows:

- Distinct characteristics of residential customers must be considered (weather sensitivity, meter data, small contributors, dynamic populations)
- The standard historical baseline is an inaccurate reflection of consumption from residential load; an alternative is required
- Contributor enrollment, registration and access to meter data must be relatively simple
- IESO should investigate address operational matters (e.g. reports, minimum aggregation)

The IESO considered accuracy, robustness, feasibility and best practices for each baseline methodology

- Historical X of Y with in-day adjustment, statistical sampling, like-day matching, regression modeling, randomized control trials, custom baselines
- A "firm service level" methodology, where a resource drops to a pre-determined consumption level, was not considered
    - This approach does not necessarily deliver demand response as the resource may already be consuming at or below its pre-determined service level.

The IESO considered a number of options:

- Historical baseline with design changes (i.e. change to high X of Y and/or adjustment)
    - easy to understand and widely used for DR

- significant data burden for dynamic population
  - accuracy for residential DR is still an issue, even with design changes
- Statistical sampling
  - accuracy for residential DR is acceptable
  - used when interval meter data not available for the entire population, but Ontario has smart meter data
- Like-day matching
  - easy to understand, some other jurisdictions are using this option
  - accuracy for residential DR is still an issue and new tools would be required
- Regression modelling
  - accuracy for residential DR is acceptable
  - complex to understand, not widely used, brand new tools would be required
- Custom baseline
  - accuracy for residential DR depends on the proposed approach
  - costly and burdensome to administer multiple different baselines
- Randomized control trials (RCT)
  - sufficient accuracy for residential load has been proven, and other jurisdictions are using or exploring this option
  - new tools are required for IESO implementation

Recommendation – RCT Baseline

- Delivers the required accuracy for M&V purposes
- Implementation for summer 2017 commitment period is feasible
- Can scale to larger volumes of residential DR participation
- Consistent with the methodologies used in other IESO programs and markets

Conclusion

The residential demand response market in Ontario has evolved in the past 9 years for many reasons, such as system needs, technological advancement, and market maturity. The evolution of evaluation methods played a key role in informing policy decision that have now led to the inclusion of residential demand response resources in the next capacity auction.

Evaluation played a critical role in the evolution of the program structure and helped create the capability to offer market based solutions for residential demand response resources. The development of the load impact evaluation protocol, developed from repeated evaluations, replicated year after year led to the building of industry capability to structure the offering to the market in a way that allows for results to be verified and the value of the resource to be clearly identified.

References

KEMA 2010. “2009 peaksaver® Residential Air Conditioner Measurement and Verification Study” *for the Ontario Power Authority.*

Freeman, Sullivan, & Company, 2013. “residential demand response® Program Load Impact and Process Evaluation” *for the Ontario Power Authority*

IESO 2017. “Market Manual 12: Demand Response Auction Part 12.0: Demand Response Auction Issue 6.0 (effective date March 31, 2017)”