Year Two Analysis of Ontario's Full Scale Roll-out of TOU Rates

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This report was prepared for the Ontario Power Authority (OPA). All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

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Executive Summary

Besides the nation of Italy, the Canadian province of Ontario is the only region in the world to have rolled out smart meters to all its residential customers and to deploy Time-of-Use (TOU) rates for generation charges to all customers who stay with the regulated supply option. TOU rates were deployed as a load shifting measure in Ontario, to persuade customers to curtail electricity usage during the on-peak period and/or to shift that usage to less expensive mid-peak and off-peak periods, and possibly to reduce overall electricity usage.

This impact evaluation of Ontario's full-scale roll-out of TOU rates is a three-year project with the following objectives: (i) Quantify the change in energy usage by pricing period for the residential and general service customers (defined below) using a few select local distribution companies (LDCs); (ii) Estimate the peak period impacts using the OPA's definition of summer peak demand; (iii) Estimate the elasticity of substitution between the pricing periods and the overall price elasticity of demand.

This report presents the findings from the second year of the study, examining impacts from TOU rates from their inception through to the end of 2013.[1] Although the objectives remain consistent with those of the report from the first year, the methodological approach of this study differs from this earlier report in the following ways:

1. Impacts are estimated at the regional level, instead of the LDC level. There are four regions, each consisting of multiple LDCs. Each region has a distinctive climate and census-profile. The regions were selected to be consistent with the way in which Hydro One divides its service territory.[2]
2. Impacts are allowed to vary by socio-demographic factors corresponding to census districts.
3. Regional impacts are calculated to represent the corresponding regional populations.
4. Representative provincial impacts are calculated by weighting the regional impacts by regional customer count shares. Impacts are calculated by calendar year. In the first year of the study impacts were calculated for the first year that customers were on TOU rates. These dates and the duration of this initial period varied by LDC.

[1] While all LDCs in the study were offering TOU rates by 2012, they started offering these rates at different points in time from 2009 onwards.

[2] Hydro One was rebranded from Ontario Hydro Services Company soon after the restructuring of Ontario's electricity market and is divided into 4 different regions based on a geographic grouping of operating centers.

5. Four additional LDCs have been added to the study: Thunder Bay Hydro; Sudbury Hydro; Cambridge North Dumfries Hydro; and PowerStream,[3] and these supplement the LDCs that were included in the first year, for which we now have an additional year of data: Hydro One, Toronto Hydro, Hydro Ottawa and Newmarket-Tay Power.[4]

The LDCs analyzed in the second year study constitute more than 50% of the Ontario population. While the original LDCs in the first year study were chosen based on their previous experience with TOU pilots, general size and geographic location, the LDCs added in the second year of the study were chosen based on geographic and demographic factors. In order to be eligible for the study, LDCs had to have a sufficiently long pre-TOU data record. In order to implement TOU rates, LDCs had to first install smart meters that recorded electricity usage at different times of the day (interval data). Once they had smart meters installed, they could roll-out the TOU rate to their customers. Each LDC in Ontario managed its TOU rate deployment independently. Both smart meters and the TOU rate were rolled out at different dates and over different time scales across the LDCs. Participant LDCs were included because they had sufficiently long pre-TOU periods, where customers had interval data but were not yet on the TOU rate. The deployment of TOU rates in Ontario was not part of an experiment and this posed an analytical challenge for constructing a control group for the impact evaluation purposes. However, heterogeneous timing of the TOU deployment worked in our favor as we were able to include customers who were at the tail end of the deployment as a proxy control group in our study (at least through the end of 2012). However, because we have included pre-TOU implementation data for the entire sample, there is a second set of control data across time.

For each region, we examined two customer classes: residential and general service. Single family homes and individually metered apartment buildings constitute the residential class and general service customers are non-residential with demands less than 50 kW. Only customers with a sufficient history of hourly data in the pre-TOU period were able to be included in the study. The final second year study sample included 112,642 residential customers and 35,991 general service customers, out of a total customer population of 2,162,063 residential customers and 147,450 general service customers for the participating LDCs. Due to insufficient pre-TOU data we were unable to include general service customers for Toronto Hydro and Newmarket-Tay Power.[5]

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[3] PowerStream was omitted from the second year study due to data availability issues, but will be included in the final year analysis.

[4] Thunder Bay Hydro was one of the original study participants but was omitted from the first year study due to data issues.

[5] For each LDC and customer class we required at least 6 months of pre-TOU incremental data. Incremental data were obtained from the installation of smart meters. If the window between smart meter installations and TOU rates was too short, then adequate pre-TOU data did not exist. This was the case for general service customers for both Toronto Hydro and Newmarket-Tay Power.

Methodology

We employ a two-pronged approach to achieve the 1st and 3rd objectives of the TOU study: (i) estimation of an advanced model of consumer behavior called the "Addilog Demand System" to discern load shifting effects that are caused by the TOU rates and to estimate inter-period elasticities of substitution; (ii) estimation of a simple monthly consumption model to understand the overall conservation behavior of the customers and estimate an overall price elasticity of demand. By using the parameter estimates from these two models and solving them together, we calculate the impact that TOU rates have had on energy consumption by period and for the month as a whole.

The 2nd objective of the TOU study is to estimate peak period impacts coinciding with OPA's EM&V Protocols and Requirements definition of peak ("OPA peak demand") which is defined as the average demand between 1pm – 7pm on weekdays (excluding public holidays) during June, July, and August.[6] It should be noted that the OPA peak is different from the TOU peak that customers see on their electricity bill, which in summer extended from 11am to 5pm. In order to estimate the OPA peak impacts, we re-estimated the Addilog Demand System model and the monthly conservation model over just the peak summer months (June - August) and load-weighted the associated period impacts to infer an average impact for the 1pm- 7pm window.

Results

The analysis is conducted at the regional level and aggregated to the provincial level. Load shifting impacts are split into three separate periods: pre-2012, 2012 and 2013. The pre-2012 period reflects all of the years that LDCs within a region were on TOU rates prior to 2012. Some LDCs started TOU as early as 2009, while others only began in 2012, resulting in compositional changes potentially affecting the comparison between pre-2012 and later years. By 2012, all LDCs in the study were on TOU rates.

The key findings are summarized below:

- Residential customers show relatively consistent patterns of load shifting behavior across regions and study years, but little evidence of conservation.
- General Service class customers show mixed evidence of load shifting behaviors and are less responsive to the TOU prices than residential customers. However, general service class customers show more conservation than the residential customers.

[6] *See* "OPA EM&V Protocols TG-6: Demand Savings Calculation Guidelines". http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and-Requirements-2015-2010.pdf

- The load shifting model parameters are generally well-behaved and have magnitudes that have been observed in other pilots.
- There are some unexpected positive elasticities in the conservation models, likely due to little price variation during the study period. None of these elasticities are statistically significant.

Residential Class:

In terms of the *residential class* results, there is significant evidence of load shifting during the OPA peak demand period across all regions in the pre-2012 and 2012 periods. However load shifting is substantially lower in 2013 in all regions except the East. For the province as a whole there was a statistically significant reduction in usage during the OPA peak of 1.85 percent in the pre-2012 period, 1.82 percent in 2012 and 0.68 percent in 2013 relative to what usage would have been in the absence of TOU. The OPA peak demand period is calculated over June, July and August from 1 to 7pm. This time period is "invisible" to consumers who only see the Ontario Energy Board ("OEB") TOU periods. The OPA peak demand period straddles two of these periods - the summer on-peak from 11am to 5pm and summer mid-peak from 5pm to 7pm, and is a subset of the OEB summer TOU pricing period, which extends from May to October.

Figure ES1 shows the impacts for the OPA peak demand period. The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage in the OPA peak demand period. The colored bars show the estimated impacts, while the black brackets show a 95 percent confidence interval for the impact. In the pre-2012 and 2012 periods the confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be highly confident that we can reject the null hypothesis of zero load-shifting in these years.

Figure ES1: Impacts for the OPA Peak Demand Period (June, July, August, 1PM – 7PM)

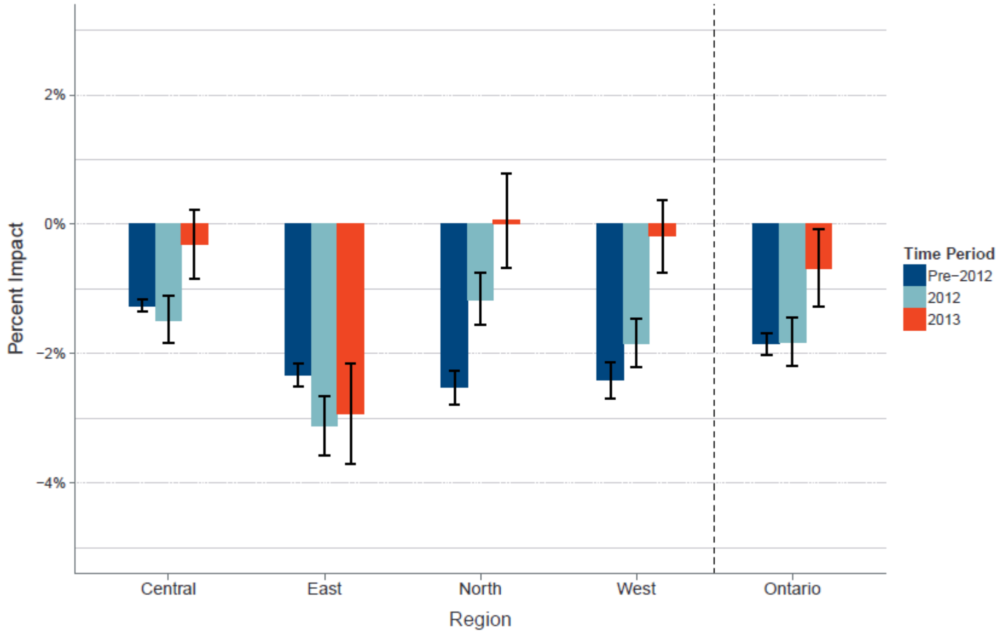
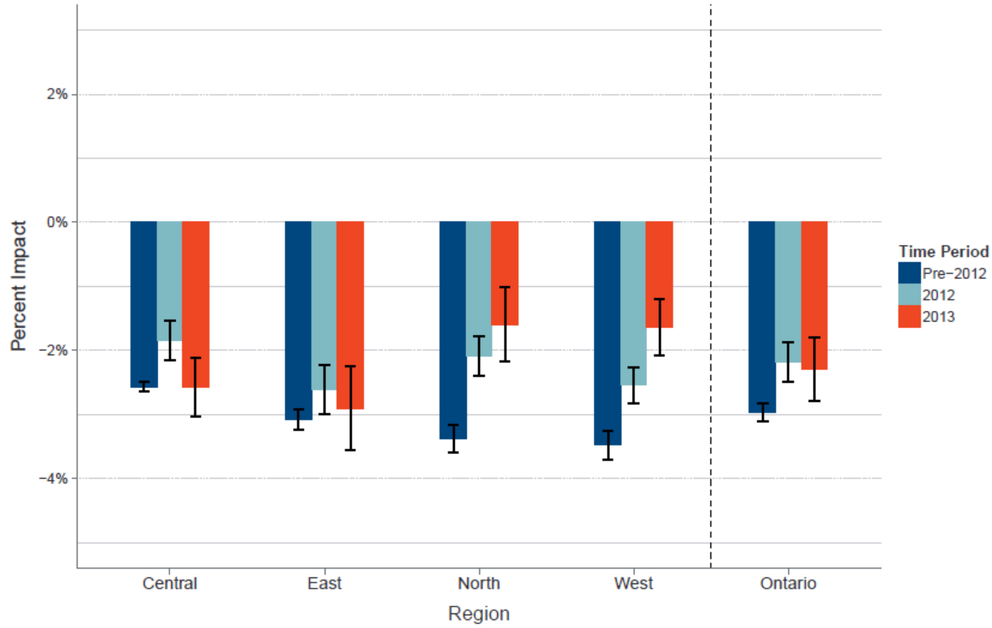


Figure ES2 shows the impacts during the summer on-peak period across the regions and province as a whole for residential customers. The summer on-peak reflects the TOU peak prices seen by customers. The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage during the summer on-peak period. For the province as a whole, TOU reduced usage during the summer on-peak by 2.96 percent in the pre-2012 period, 2.18 percent in 2012 and 2.29 percent in 2013, relative to what usage would have been in the absence of TOU. The confidence intervals on these impacts are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be highly confident that we can reject the null hypothesis of zero load-shifting in all years and regions. For the provincial impact measures we can see that summer on-peak period impacts were slightly larger in the pre-2012 period, but very similar in 2012 and 2013.

It is unclear from the data available to us why customer response dipped in the inner summer months of the 2013 OPA peak demand period, but not for the summer as a whole, especially since all of the data is weather normalized.

Figure ES2: Residential Load Shifting Results (Summer On-Peak Period)



While we chose to focus on summer results, we also estimate load shifting impacts for the winter. These are smaller than in the summer rate period in the earlier years, but are more or less equal by 2013. More details on winter load-shifting can be found in Appendices s 1 through 4.[7] Lastly, there is no evidence of energy conservation (This is discussed in more detail in section V subsection B).

General Service Class:

In terms of the *general service class* results, we find that there is some evidence of load shifting across all regions, with reductions in usage in the on-peak and mid-peak periods and small increases in the off-peak periods. Impacts are far smaller than those estimated for the residential customer class, the results are not as unambiguous, and there are some odd substitution patterns. Further, impacts are largely not statistically significant. This is most likely an artifact of the heterogeneity in the general service class data.

For the province as a whole there was a reduction in usage during the OPA peak of 0.82 percent in the pre-2012 period, 0.17 percent in 2012 and 0.17 percent in 2013 relative to what usage would have been in the absence of TOU. Only the pre-2012 impact was statistically significant and distinguishable from a zero impact.

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[7] See the associated tables labelled 'Region *X* Winter Residential/General Service TOU Impacts" and "Region *X* Residential/General Service Winter Elasticities", and charts labelled 'Loadshifting for Region *X* Winter Residential/General Service").

During the summer on-peak period, TOU reduced usage by 0.78 percent in the pre-2012 period, 0.21 percent in 2012 and 1.28 percent in 2013, relative to what usage would have been in the absence of TOU. Both the pre-2012 and 2013 impacts were statistically significant and distinguishable from a zero impact, while the 2012 impact was not.

Evidence on energy conservation was limited, with all estimates showing very small (smaller than 0.5%) conservation impacts.

Limitations of the Study

As stated earlier, the TOU roll-out in Ontario was not a randomized control experiment.[8] This posed some unique challenges in study design. We were able to exploit the phased nature of the deployment to approximate a "difference-in-differences" analysis. The amount and quality of the pre-TOU data differed widely across LDCs. By determining an eligible customer list with at least six months of pre-TOU data, we have mitigated this issue to a large extent.[9] We use this variation to estimate three calendar year effects – the pre-2012 year(s), 2012, and 2013 – at the regional level.

However, little price variation between the pre-TOU and TOU period led to difficulties with conservation equations. We zeroed out implausible (and statistically insignificant) conservation elasticities for impact calculations.

While we correct for serial correlation in the monthly consumption model, we did not have the time to do so for the addilog system in the second year study. [10] We plan to correct our Seemingly Unrelated Regression (SUR) estimation of the addilog demand system for serial correlation in the final year of the TOU study.[11] For our current assumptions, the standard errors are precise.

8 In randomized controlled experiments, eligible customers are randomly allocated into the treatment and control groups. The treatment group customers receive the "treatment" (TOU rates in this context), whereas the control customers do not receive the treatment.

9 At least six months' data availability was required for determining the list of eligible customers. Once we verified that there were a large number of customers with at least six months of pre-TOU data availability, we have selected our sample and requested at least twelve months of pre-TOU data to be provided to us for the impact evaluation. The passage I have highlighted in yellow above struck me as odd … after we had been reading about 'six months'. … It is perhaps that six months is the 'qualifying (minimum)', and that whoever qualified was then asked for 12 months (if they had it)?

10 Serial correlation is the correlation of a variable with itself over successive time periods.

11 Seemingly Unrelated Regression is a generalization of a linear regression model that consists of several regression equations with the error terms from each regression equation being correlated with the error terms from another.

However, we have tried a few simulations where we varied the standard errors in the SUR estimation by a factor of two and we still found our confidence bands did not contain zero.

Lastly, the customer sample has the following limitations. First, the Newmarket-Tay Power sample may not be representative of the relevant population. Second, due to data availability and timing issues, we are not able to include General Service customers for Toronto Hydro and Newmarket-Tay Power. We also excluded Sudbury retail customers and all of PowerStream's customers from the second year study, but expect to include them in the final year study.[12]

[12] Retail customers, who have opted out of the regulated price plan offered by their local LDC, act as an additional control group, since they will not be placed on TOU rates.

I. Introduction

Pursuant to the *Electricity Restructuring Act, 2004*, the Ontario Energy Board ("OEB") is mandated to develop a regulated price plan (the "RPP"), which includes a Time-of-Use (TOU) pricing structure whose purpose is to provide stable and predictable electricity pricing for consumers that more accurately reflects the actual costs of generation.

As part of TOU implementation, each of the 76[13] LDCs in Ontario is accountable for:

- undertaking the installation of smart meters for all residential customers and general service customers under 50 kW;
- enrolling smart meters in the centralized provincial Meter Data Management Repository ("MDM/R"); and
- activating TOU pricing across its service territory.[14]

LDC progress on TOU implementation is monitored by OEB-mandated monthly reporting obligations, which ended on 30 June of 2012.[15] As of this date, 99 percent of the RPP eligible customers had their smart meters installed; 92 percent were enrolled with MDM/R, and 89% were on TOU billing.

TOU prices are set by the OEB and reviewed bi-annually in May and November.[16] The OEB price review is based on an analysis of electricity supply cost forecasts for the year ahead and a true-up between the price paid by consumers and the actual cost of generation in the previous billing period. Consumers may be exempted from TOU pricing by executing a fixed-price contract with an electricity retailer for a term generally between three to five years.

Besides Italy, Ontario is the only region in the world to roll out smart meters to all its residential customers and to deploy TOU rates for generation charges to all customers who stay with regulated supply.

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13 In Ontario, there are a total of 76 LDCs, however only 73 of these are subject to OEB regulations. The remaining 3 LDCs are not compelled to install smart meters or to impose TOU rates.

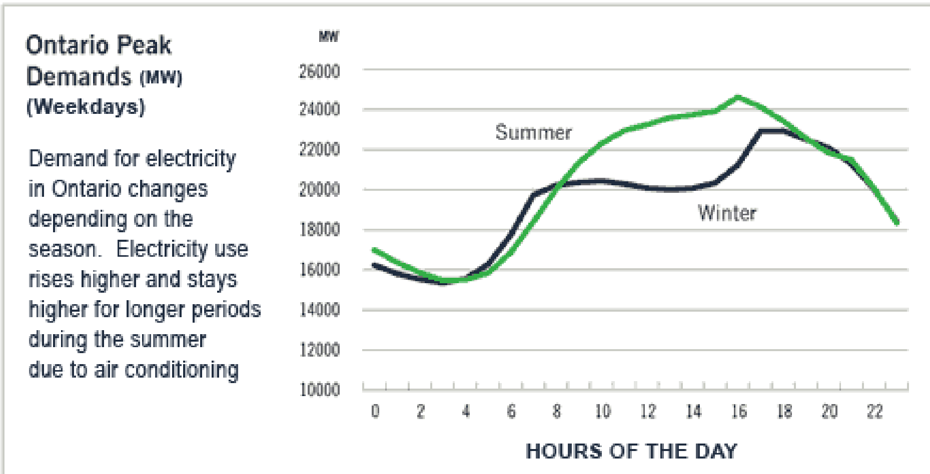
14 Full implementation of TOU pricing across all LDC service territories was initially scheduled for June 2011. However LDCs had the opportunity to apply for full or partial OEB exemption from this compliance deadline due to limitations with existing telecommunications infrastructure and other circumstances

15 http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Smart+Metering+Initiative+(SMI)/Smart+Meter+Deployment+Reporting

16 www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Smart+Meters/FAQ+-+Time+of+Use+Prices

The rationale for TOU pricing is clear. Electricity cannot be stored economically in large quantities and the demand for electricity varies throughout the day. On weekdays, demand starts to rise in the morning as people get up and continues to its peak in the late afternoon or evening as people come home. On weekends and holidays, demand is lower overall. This is illustrated in Figure 1.1.

Figure 1.1: Ontario's Load Profile

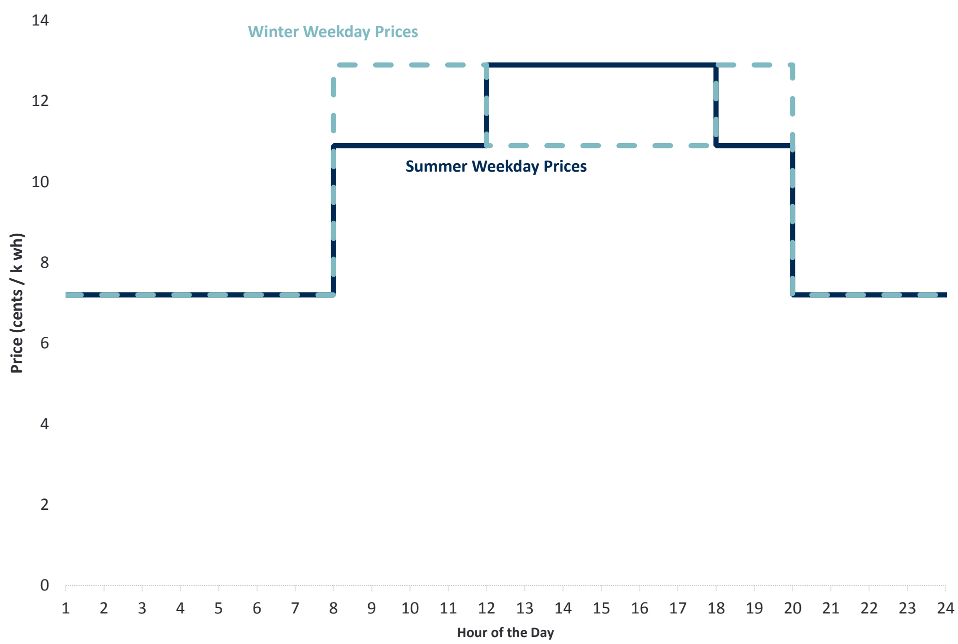


Source: Independent Electricity System Operator at www.ieso.com.

Weather exercises a very important influence on how much and when Ontarians consume electricity. Over the last few decades, peak demands have become much more pronounced over the summer months as more people install air conditioning in homes and businesses. Peaks in the summer usually take place in the mid- to late-afternoon. The amount of daylight also affects peak. In the winter, increases in usage typically occur in the morning, when people wake-up in darkness to begin their day and peaks in the afternoon when the sun sets relatively early. TOU rates were deployed as a load shifting measure in Ontario, to incentivize customers to curtail electricity usage during the on-peak period and/or to shift that usage to less expensive mid-peak and off-peak periods, and possibly to reduce overall electricity usage. By conserving or shifting electricity use during peak periods, consumers can take an active role in the management of Ontario's electricity system.

Ontario's TOU consists of three pricing periods. Only the commodity (generation) prices are time varying. These are determined by the Ontario Energy Board (OEB) and are seasonal and may be adjusted every six months to reflect changes in system conditions and market prices. An illustration of the relevant TOU periods and commodity prices (effective November 2013) is shown in Figure 1.2.[17] It should be noted that these TOU prices account for roughly only half of the average customer's bill; other charges that the customers face are not time-varying.

Figure 1.2: Electricity Prices across a day (in effect as of November 2013)



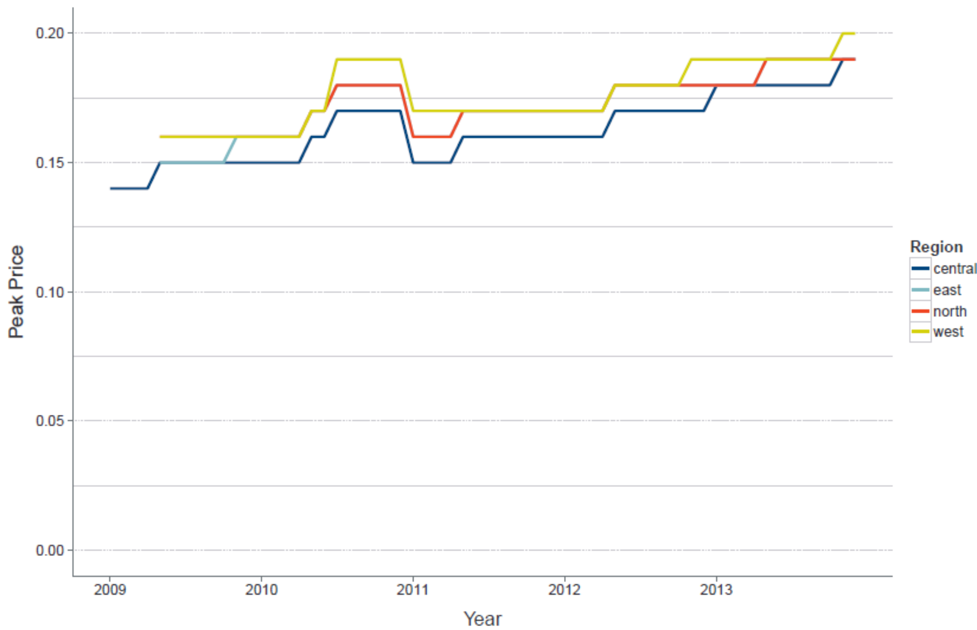
Source: Ontario Energy Board, URL: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices#tou

Historically, these prices have risen over time. See Figure 1.3 below for the historical all-in on-peak price across the four regions used in the study. These regions are used to separate Ontario into 4 distinct climate zones, with each region analyzed separately. Figure 1.3 shows that the Western region has had consistently higher prices than the other regions. The all in price includes the TOU price for generation as well as other prices that don't vary by time of day (but do vary across LDCs) such as distribution costs, uplift factors, network charges, connection charges, loft factors, wholesale market charge, etc. All-in prices also include the clean energy rebate, which after September 2012 entered in as a tiered rate.[18]

17 Source: Ontario Energy Board website. http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices

18 The clean energy rebate originally affected rates in May 2011 for all customers. However, in September 2012, the clean energy rebate was confined to the first 3000 kWh of consumption.

Figure 1.3: All-In TOU On-Peak Price by Region 2009 - 2013



Differentials between the on-peak and off-peak prices have remained relatively stable since 2010. As of November 2013, the on-peak to off-peak price ratio is 1.8 for the generation component only. When other non-volumetric bill components are included (excluding customer charges) to result in an "all-in" rate, the on-peak to off-peak price ratio is roughly 1.5.

Now that TOU rates have been deployed for two or more years at most LDCs, the data exist to measure the changes in customer usage patterns that have occurred in response to the TOU rates. The measurements will be carried out over a three year period. This report contains the Second Year Impact Evaluation of the TOU rates in Ontario by carrying out an econometric analysis at the regional and provincial levels.

II. Study Objectives

The Second Year study has three primary objectives:

1. Quantify the change in energy usage by pricing period for the residential and general service customers for each of the four Ontario regions, containing seven LDCs in total;
2. Estimate the peak period impacts using the OPA's peak demand period definition.
3. Estimate the elasticity of substitution between the pricing periods and the overall price elasticity of demand;

In the Second Year study, we originally planned to analyze hourly customer data from four regions in eight LDCs as follows:

- East: Hydro One East, Hydro Ottawa
- Central: Hydro One Central, Toronto Hydro, Newmarket-Tay Power, PowerStream

- West: Hydro One West, Cambridge North Dumfries Hydro
- North: Hydro One North, Thunder Bay Hydro, Sudbury Hydro

However, owing to insufficient pre-TOU interval data, the general service analysis excludes general service customers from Toronto Hydro and Newmarket-Tay Power. All PowerStream customers and Sudbury retail customers were also excluded from the study, but will be included in the final study year. Retail customers, who have opted out of the regulated price plan offered by their local LDC, act as additional control group, since they will not be placed on TOU rates.

The LDCs included in the Second Year study constitute more than 50% of the Ontario population of residential customers. While the original LDCs in the first year study were chosen based on their previous experience with TOU pilots, general size and geographic location,[19] the LDCs added in the second year study were chosen based on geographic and demographic factors. In order to be eligible for the study, LDCs had to have a sufficiently long pre-TOU data record of preferably one year, but at least six months. In order to implement TOU rates, LDCs had to first install smart meters that recorded electricity usage at different times of the day (interval data). Once they had smart meters installed, they could roll-out the TOU rate to their customers. Each LDC in Ontario managed its TOU rate deployment independently. Both smart meters and the TOU rate were rolled out at different dates and over different time scales across the LDCs. Participant LDCs were included because they had sufficiently long pre-TOU periods, where customers had interval data but were not yet on the TOU rate. Even though the TOU roll-out was not a randomized control experiment, we were able to exploit the phased nature of the deployment to approximate a "difference-in-differences" analysis.[20] Moreover, we relied on the data for customers who are at the tail end of the deployment as well as retail customers who aren't on TOU rates to constitute the control group.

For each region, we examined two customer classes: residential and general service. Single family homes and individually metered apartment buildings constitute the residential class and general service customers are non-residential with demands less than 50 kW. Only customers with a sufficient history of hourly data in the pre-TOU period were able to be included in the study. The final year two sample included 112,642 residential customers and 35,991 general service customers, out of a total customer population of 2,162,063 residential customers and 147,450 general service customers for the participating LDCs.

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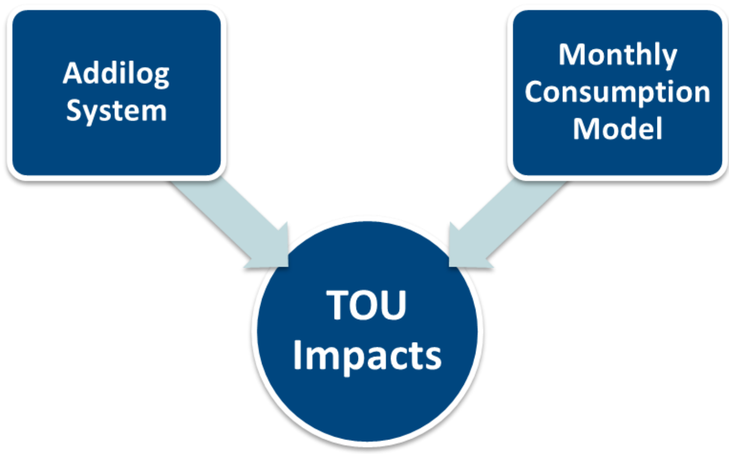
[19] See the first year study for more details: http://powerauthority.on.ca/sites/default/files/conservation/Preliminary-Report-First-Year-Impact-Evaluation-of-Ontario-TOU-Rates.pdf

[20] Difference-in-Differences is a conceptual technique for ensuring that TOU impact measurements do not include any changes that would have occurred in the absence of TOU. It does this by netting off any changes that occur between the post-TOU and pre-TOU periods for customers who never received TOU from those who did.

III. Methodology

We employ a two-pronged approach to achieve the first and second objectives of the TOU study: (1) estimate an advanced model of consumer behavior called the Addilog Demand System to discern load shifting effects that are triggered by the TOU rates and to estimate inter-period elasticities of substitution; the Addilog Demand System is estimated over six pricing periods that are described later; (2) estimate a simple monthly consumption model to understand the overall conservation behavior of the customers and to estimate an overall price elasticity of demand.[21] By using the parameter estimates from these two models and solving them together, we calculate the impact that TOU rates have had on energy consumption by period and for the month as a whole.[22]

Figure 3.1: Two-pronged Approach to Estimating the TOU impacts



[21] In this study, we estimate two types of elasticities. The first one is the "substitution elasticity" which indicates the percent change in the ratio of peak-to-off-peak consumption due to 1% change in the peak-to-off-peak price ratio (of the all-in price). For instance, a substitution elasticity of -0.10 implies that, when the peak-to-off-peak price ratio increases by 1%, the usage ratio decreases by 0.10%. In the economics literature, the negative sign is removed from the substitution elasticity. However, consistent with our prior papers on the subject, we have kept it in, since it is mathematically correct and easier to interpret. The second one is the "overall conservation elasticity" which indicates the percent change in the average monthly consumption due to a 1% change in the average monthly all-in price. For instance, an overall conservation elasticity of -0.05 implies that, when the average monthly price increases by 1%, the average monthly usage decreases by 0.05%

[22] Originally, we had planned to survey the customers included in the sample and use the survey data to be able to report the impacts for different customer characteristics. However, due to limitations in customer privacy, whereby customer identities were strictly anonymized, we were not able to survey the customers analyzed in this study.

The 3rd objective of the TOU study is to estimate peak period impacts as defined by the OPA's EM&V Protocol definition. The OPA peak demand is defined as the average demand between 1pm – 7pm on weekdays during June, July, and August. To achieve this objective, we re-estimate the Addilog Demand System and the monthly conservation model over just the peak summer months (June - August) and reweight the on-peak and evening mid-peak impacts to infer an average impact for the 1pm- 7pm window.[23]

Below, we describe each of the estimated models in detail.

A. Addilog Demand System Estimation

As indicated above, we estimate an advanced model of consumer behavior called the "Addilog Demand System" to discern load shifting effects that are triggered by the TOU rates and to estimate inter-period elasticities of substitution.

The Addilog System, first formulated by Houthakker (1960, *Econometrica*) and more recently extended by Conniffe (2006, *Canadian Journal of Economics*) and Jensen, et al. (2011, *Journal of Economics*), is a well-behaved demand system, which is capable of estimating small elasticities of substitution.[24] Unlike more flexible demand systems, the Addilog System, like the Constant Elasticity of Substitution ("CES") demand system, is known to satisfy regularity conditions (e.g., concavity) globally. As noted in Mountain and Hsiao (1989, *Journal of the American Statistical Association*), even though the intent of flexible functional forms is to permit testing of hypotheses about elasticities of substitution over a wide range of possible data points, the available Monte Carlo studies (e.g., Gallant (1981, *Journal of Econometrics*) and Guilkey, Lovell, and Sickles (1983, *International Economic Review*)) and the results of Caves and Christensen (1980, *American Economic Review*) suggest that the available flexible functional forms cannot totally serve the purposes for which they were originally produced. Consequently, the CES was also used in earlier work by Caves and Christensen (*The Energy Journal,* 1980) who analyzed data from the Wisconsin TOU experiment and later in a meta-analysis of data from five TOU experiments (*Journal of Econometrics,* 1983). Moreover, as a reflection of the advantages of these more parsimonious demand systems for estimating the impact of dynamic pricing, many recently published papers in applied energy journals has used the CES demand system. For example, see the published papers of Faruqui and Sergici (2011, *Journal of Regulatory Economics*), Faruqui and George (2005, *The Electricity Journal*), Faruqui, Sergici and Akaba (*The Energy Journal*,

23 Period 4 covers the 11am – 5pm window (peak) and period 5 covers the 5pm – 7pm window (mid-peak). The period definitions are introduced later in the report.

24 Unlike more flexible functional forms, which can violate the second-order conditions for utility maximization, the Addilog Demand System is globally concave and always satisfies those conditions. This property is not only valuable for estimating theoretically consistent elasticities but also essential for estimating out-of-sample province-wide impacts. (This is a reason Addilog Sytems are often used in Computable General Equilibrium models for long-term simulations.)

2014) and Faruqui, Sergici and Akaba (*Energy Efficiency*, 2013), in their analyses of the pricing experiments in Baltimore, California, Connecticut, and Michigan, respectively.

We estimated the Addilog system separately for summer and winter seasons over six pricing periods.

Figure 3.2 TOU Study Time Periods

Period	Hours	Summer TOU Window (May - October)	Winter TOU Window (January - April, November & December)
1	-	Weekends & Holidays	Weekends & Holidays
2	9 pm - 7 am	Off-peak	Off-peak
3	7 am - 11 am	Mid-peak	Peak
4	11 am - 5 pm	Peak	Mid-peak
5	5 pm - 7 pm	Mid-peak	Peak
6 (*)	7 pm - 9 pm	Off-peak	Off-peak

(*) Before May 2011, period 6 was a summer mid-peak and winter peak period.

Following is a generalized Addilog System for the six TOU periods, with period 1 acting as base:

$$\ln\left(\frac{q_{2ht}}{q_{1ht}}\right) - \ln\left(\frac{q_{2ht-12}}{q_{1ht-12}}\right) = \beta_2\left(\ln\left(\frac{P_{2ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{2ht-12}}{Y_{ht-12}}\right)\right) - \beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right) + \sum_{k=1}^{K}\gamma_{k2}\left(X_{k2ht} - X_{k2ht-12}\right) + \nu_{2ht}$$

$$\ln\left(\frac{q_{3ht}}{q_{1ht}}\right) - \ln\left(\frac{q_{3ht-12}}{q_{1ht-12}}\right) = \beta_3\left(\ln\left(\frac{P_{3ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{3ht-12}}{Y_{ht-12}}\right)\right) - \beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right) + \sum_{k=1}^{K}\gamma_{k3}\left(X_{k3ht} - X_{k3ht-12}\right) + \nu_{3ht}$$

$$\ln\left(\frac{q_{4ht}}{q_{1ht}}\right) - \ln\left(\frac{q_{4ht-12}}{q_{1ht-12}}\right) = \beta_4\left(\ln\left(\frac{P_{4ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{4ht-12}}{Y_{ht-12}}\right)\right) - \beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right) + \sum_{k=1}^{K}\gamma_{k4}\left(X_{k4ht} - X_{k4ht-12}\right) + \nu_{4ht}$$

$$\ln\left(\frac{q_{5ht}}{q_{1ht}}\right) - \ln\left(\frac{q_{5ht-12}}{q_{1ht-12}}\right) = \beta_5\left(\ln\left(\frac{P_{5ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{5ht-12}}{Y_{ht-12}}\right)\right) - \beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right) + \sum_{k=1}^{K}\gamma_{k5}\left(X_{k5ht} - X_{k5ht-12}\right) + \nu_{5ht}$$

$$\ln\left(\frac{q_{6ht}}{q_{1ht}}\right) - \ln\left(\frac{q_{6ht-12}}{q_{1ht-12}}\right) = \beta_6\left(\ln\left(\frac{P_{6ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{6ht-12}}{Y_{ht-12}}\right)\right) - \beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right) - \ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right) + \sum_{k=1}^{K}\gamma_{k6}\left(X_{k6ht} - X_{k6ht-12}\right) + \nu_{6ht}$$

Where:

X refers to non-TOU variables such as weather characteristics; h refers to customer; t refers to month; q and P refer to the consumption and prices in the specific time period, respectively; Y refers to overall electricity expenditure, and ν is a random disturbance.

The price and weather terms are implemented as vectors of parameters that allow us to obtain:

1) Separate impacts estimates for pre-2012, 2012 and 2013 periods
2) Heterogeneous responses to prices and weather based on postal code level demographics.

To this end we have

$$\beta_i = \beta_{i\,pre-2012} + \beta_{i\,2012} * I(2012) + \beta_{i\,2013} * I(2013) + \beta_{ic1}PCX1 + \beta_{ic2}PCX2$$

And

$$\gamma_{ki} = \gamma_{ki0} + \gamma_{kic1}PCZ1 + \gamma_{kic2}PCZ2$$

Where:

- $I(2012)$ is an indicator if the calendar year is greater than or equal to 2012
- $I(2013)$ is an indicator if the calendar year is greater than or equal to 2013
- PCX1 and PCX2 are the first two principal components of census variables that would influence price responsiveness
- PCZ1 and PCZ2 are the first two principal components of census variables that would influence weather responsiveness

More details on the principal components are available in Section D below.

The above system of equations was estimated using the "Seemingly Unrelated Regression (SUR)" estimation routine. Even though the set of equations seem unrelated to each other, they are actually related through the correlation in their error. This routine also allows us to enforce cross-equation restrictions, i.e., the coefficient of the period 1 price will take the same coefficient in all five equations, etc. SUR employs random effects estimator in the context of unbalanced panels (time-invariant fixed effects are accounted for using first differences). This systems estimation is consistent with the procedure used by Ham, Mountain, and Chan (1997, *Rand Journal of Economics*) where household specific effects (for which we have very little information) are differenced out avoiding possible selection biases regarding those who opted for not choosing a retail rate. Separate systems were estimated for the summer and winter. Here are the overall steps followed in estimating the Addilog System.[25]

1. Based on the census data for each region, construct principal components to capture sensitivity to price and weather;
2. Construct monthly average consumption levels for six time periods corresponding to the TOU periods on weekdays and weekends;
3. Normalize each period's price by the monthly expenditure for the corresponding month;
4. Take the natural logarithm of the price and quantity variables (but not the logarithm of the weather variables, as all the observations with 0 values would be lost with the logarithms);
5. Assign period 1 as the baseline period relative to which we represent quantities, prices, and weather variables of all other five periods;
6. Take the first differences of each of the regression variables by subtracting the previous year's values from the current year's values. First differencing will account for self-selection bias concerns related to specific fixed customer attributes that may prompt them to select into retail rates;
7. Parameter estimates from the Addilog system readily yield elasticity of substitution for all five periods relative to the first period.[26] Other elasticities (such as own price and cross price elasticities) can also be derived from the estimated Addilog system.

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25 While we correct for serial correlation of the error term in the monthly consumption model, we were unable to do so for the Addilog System which estimates the load shifting impacts because of time constraints. Under a certain set of assumptions, we have correctly estimated the standard errors. We plan to incorporate a correction for serial correlation in the Addilog System in the final year of this study. However, to get a rough idea of the imprecision in the standard error estimates, we have run a few simulations based on the standard errors in the Addilog estimation being understated by a factor of two. Using this rule of thumb, we still find that the estimated impacts would be statistically significant at the 95 percent confidence level.

26 The above Addilog Demand System encompasses the CES formulation $(\beta_1 = \beta_2 = ... = \beta_6)$ and is known to be very robust in detecting small elasticities, customarily encountered in TOU implementation.

Continued on next page

It is important to note that the demand systems approach is needed not only to predict the impact of the TOU rates that have actually been deployed but also to predict the impact of alternative TOU rates in the future.

B. Monthly Conservation Model

The Addilog system and the load shifting behavior is only one piece of the puzzle. The other piece is the monthly conservation model. We estimate a monthly conservation model to estimate the overall price elasticity of demand and the conservation impact. Our model takes the following generalized form:

$$\ln Q_{ht} - \ln Q_{ht-12} = \theta\left(\ln\left(\frac{PE_{ht}}{CPI_t}\right) - \ln\left(\frac{PE_{ht-12}}{CPI_{t-12}}\right)\right) + \sum_{k=1}^{K} \tau_k \left(X_{hkt} - X_{hkt-12}\right) + e_{ht}$$

Where:

X refers to non-TOU variables such as weather; h refers to customer; t refers to month; PE is the overall monthly price of electricity; CPI is the consumer price index; Q is the monthly consumption of electricity; and e is a random disturbance.

As with the addilog model we allow for heterogeneous reactions to price and weather. Price terms are interacted with pricing Principal Components

$$\theta = \theta_1 + \theta_{2c1} PCX1 + \theta_{2c2} PCX2$$

Weather terms are interacted with weather Principal Components and vary by season

$$\tau_k = \begin{array}{l} \tau_{k1S} I(summer) + \tau_{k1c1S} I(summer) PCZ1 + \tau_{k1c2S} I(summer) PCZ2 \\ + \tau_{k1W} I(winter) + \tau_{k1c1W} I(winter) PCZ1 + \tau_{k1c2W} I(winter) PCZ2 \end{array}$$

As before, PCX1 and PCX2 are the first two principal components of census variables that would influence price responsiveness and PCZ1 and PCZ2 are the first two principal components of census variables that would influence weather responsiveness. More details on the principal components are available in Section D below.

Here are the steps followed in estimating the monthly conservation model:

Continued from previous page

Furthermore, the Addilog Demand System is globally concave. Another nice feature of the Addilog System is that it does not constrain the commodity expenditure elasticities to be 1 (homotheticity). This implies that the overall conservation coming from TOU would not necessarily correspond to equiproportional decreases in all time periods.

1. Construct monthly consumption variable by multiplying the average usage and the number of hours in each period and aggregating over all six periods;
2. Construct average monthly price by dividing the monthly expenditure by monthly usage and convert to real prices using the LDC-specific CPI series;
3. Construct monthly CDH and HDW variables by summing up the period totals and calculating a monthly average;
4. Take the natural logarithm for monthly consumption and price (do not take logarithm for the weather variables);
5. Take the first differences.

We estimate the monthly conservation model using fixed effects estimation corrected for the 1st order autocorrelation. Parameter estimates from this equation yield the overall price elasticity of demand.

After estimating the Addilog system and monthly consumption models for summer and winter seasons by class, we then solve these equations together and calculate the impacts by period. These impacts are summarized in Section V.

C. OPA Peak Model

The OPA defines their peak as the average demand between 1pm and 7pm on weekdays during June, July, and August. The OPA peak demand window, 1pm-7pm, is not a standalone time period from the customer perspective, or in our modeling framework, but it is a combination of peak and mid-peak periods. As the OPA peak period covers the time window from 1pm to 7pm, our estimate of impact for that period has to be consistent with the impacts in the on-peak and mid-peak periods that overlap extensively with the OPA peak period. To be able to achieve that consistency, we have adapted the methodology described above to account for the OPA peak demand definition. Here are the steps followed in estimating the OPA peak demand model:

1. Estimate the Addilog and monthly conservation models for the OPA peak demand months of June, July, and August;
2. Calculate the impacts for each of the six periods;
3. Calculate a weighted average impact for the peak period by aggregating the results of Period 4 (11am – 5pm) and Period 5 (5pm – 7pm) impacts. We use the non-TOU period loads for Periods 4 and 5 as the weights.

The results are summarized in Section V.

D. Variation in Customer Responses

To capture variation in how customers responded to TOU rates within each region, we interacted the price and weather impacts with census variables. This allows for customers in different census areas with different characteristics to respond differently to both prices and weather. These heterogeneous responses were then used to move from our sample impacts to a representative impact for the population of each region. This was done by re-weighting impacts, which are a function of customer characteristics, by the correct proportion of characteristics for the population of the region. For example, let's say that the impact was a function of household size such that the impact was 0.1*household size. If the average household size in the sample was 2, but the average household size in the region was 3, we can move from the sample impact to a representative regional impact by inserting 3, the region's average household size, into the equation.

While the idea of interacting impacts with census variable is theoretically attractive, there are many census variables of interest and if we interacted all of them with price and/or weather, the model would "explode" due to the large number of parameters to estimate. We therefore collapse census variables into principal components. Principal component analysis is a relatively common statistical procedure that converts a set of observations of possibly correlated variables into a smaller set of values of uncorrelated variables called principal components. Put differently, principal components capture the maximum amount of variation in explanatory variables with a small number of scores which are weighted averages of the underlying variables.

We selected seven census variables that we thought would influence price responsiveness and four to explain weather responsiveness. By collapsing these census variables into two principal components for price and two principal components for weather we could capture most of the variation in these census variables. The two price principal components capture 85.9 to 92.3 percent of the variation in the seven price sensitive census variables, depending on the region. The two weather principal components capture 82.5 to 86.8 percent of the variation in the four weather sensitive census variables, depending on the region.[27]

[27] In choosing the number of variables represented in the principal components, our objective was to confine the number of principal components to two or less. The reason was that each additional principal component used in the system of equations added an additional 18 coefficients. We did try constructing principal components using all 11 variables, but we would have had to use at least 3 principal components to capture the amount of variation we are now capturing with two principal components associated with price sensitivity and weather sensitivity coefficients. In dividing up the original variables that would influence price sensitivity versus weather sensitivity we made use of variables found to affect price or weather sensitivity in other studies. Variables more likely to influence price sensitivity are demographic and income characteristics. On the other hand, variables more likely to influence weather sensitivity (which ultimately affects electricity used for air conditioning and electric heating) are characterizations of the dwelling type. Also, the variables we used were limited to those collected by Statistics Canada's census by postal code.

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Below are the seven variables that could influence price responsiveness:

1) Average number of persons in private households relative to Ontario average;
2) Median after-tax household income relative to Ontario average;
3) Proportion of population between ages 0 and 14;
4) Proportion of population with ages 65 and over;
5) Proportion of households with after-tax income less than $20,000;
6) Proportion of households with after-tax income greater than $90,000;
7) Proportion of owned occupied private dwellings

And the four variables that could influence weather responsiveness:

1) Proportion of occupied private dwellings built before 1985;
2) Proportion of occupied private dwellings built after 1995;
3) Average number of rooms per dwelling relative to Ontario average;
4) Proportion of private single-detached private dwellings

IV. Data

A. Data Compilation

The data compilation process for the TOU study was the largest EM&V data collection process to date carried out by the OPA and the partner LDCs. The first year study was also the first time that large volumes of data were extracted from the MDM/R for evaluation purposes.

The process started in the first year of the study with the development of privacy and data collection protocols by the OPA and The Brattle Group. The OPA oversaw the entire data collection process, ensuring OPA's privacy and data collection protocols were respected by all parties involved. Throughout the data compilation process, The Brattle Group provided technical guidance and supported the LDCs and the IESO. While the LDCs provided data required for the sample size calculations and the hourly interval data for the pre-TOU period, the IESO extracted the hourly interval data for the post-TOU period from the MDM/R. eMeter provided the data extraction templates and the virtual platform for data transfer between the LDCs and The Brattle Group. This protocol was followed in second year study with some simplifications in how sample customers were selected from the LDCs. Figure 4.1 provides an overview of the data compilation process for the second year of the study.

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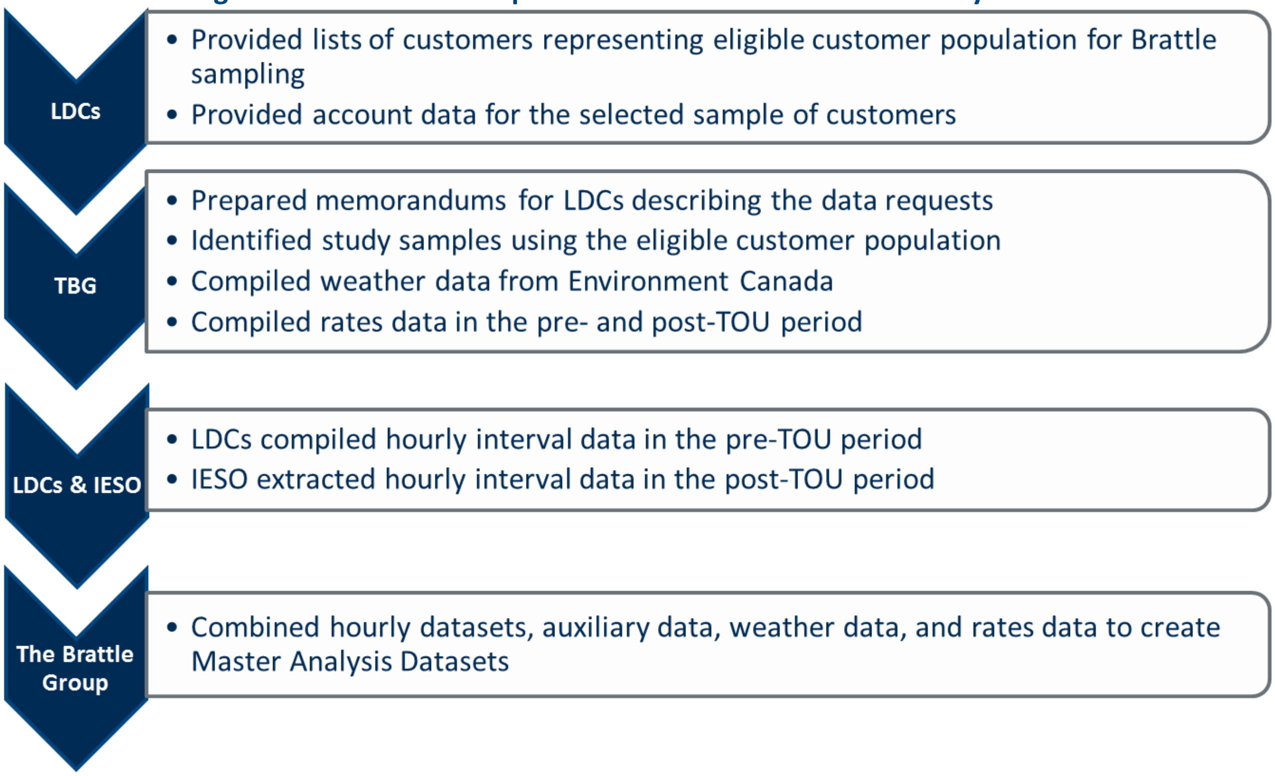
Figure 4.1: The Data Compilation Process for the Second Study Year



B. DETERMINING SAMPLE SIZES

In studies with repeated measurements taken at points preceding and following a treatment, it is possible to achieve a substantial increase in efficiency (variance reduction) due to the correlation between measurements at different time points as compared to studies with single measurements. The increased efficiency in measurements implies that it is possible to meet a given statistical reliability criteria with a smaller sample size. This study will utilize repeated measurements for study participants (*i.e.*, a panel data structure). Therefore, it will be possible to measure a given impact with desired precision by using a smaller sample size.

In the first year study, we conducted "statistical power calculations" in order to determine the minimum sample sizes required to achieve a pre-determined statistical precision level. As the on-peak to off-peak ratio is relatively low (roughly 1.5), based on our work on 34 pilots from around the globe summarized in the Arcturus database, we expected the peak and conservation impacts flowing from the TOU rates to be small. This implied that we would need larger sample sizes to be able to detect a statistically significant impact than other studies that had used higher price ratios.

In the second year study we elected to take the sample size for new LDCs using the maximum percentage of the population chosen for the sample from the first year study by customer class. First year study sample sizes showed some consistency within customer class. This eliminated the need for gathering sampling data from the new LDCs. The sample sizes this year are shown below in Figure 4.2.

Figure 4.2: Population and Sample Customer Counts for Each LDC and Region

Region	LDC	Residential (# Accounts)		General Service (# Accounts)	
		Sample Size	Population	Sample Size	Population
Central	Hydro One Central	8,647	365,798	7,887	32,905
	Toronto Hydro	47,280	629,049	-	-
	Newmarket-Tay Power	2,929	29,873	-	-
North	Hydro One North	8,571	161,606	5,271	20,207
	Thunder Bay Hydro	3,441	44,749	1,518	4,485
	Sudbury Hydro	2,001	42,279	649	3,940
West	Hydro One West	8,689	224,939	7,310	26,280
	Cambridge North Dumfries Hydro	4,768	46,122	2,940	4,691
East	Hydro One East	7,660	339,592	7,001	31,208
	Hydro Ottawa	18,656	278,056	3,415	23,734
Central	Subtotal for participating LDCs	58,856	1,024,720	7,887	32,905
North		14,013	248,634	7,438	28,632
West		13,457	271,061	10,250	30,971
East		26,316	617,648	10,416	54,942
Total		112,642	2,162,063	35,991	147,450

Note:
Retail accounts are included in these counts.

For a customer to be eligible for the study, they needed at least six months of pre-TOU and one year of post-TOU hourly billing data. Each utility varied in when they started and ended installing both AMI meters and when they started and ended their TOU roll-out. This leads to substantial variation in the amount of pre-and-post TOU data available for our study.

The maximum sample size for each LDC was not reached simultaneously because not all smart meters were rolled out simultaneously and neither was the TOU rate. Customers can be on one of three rate types at any point in type: the regulated non-TOU rate (before TOU was rolled out), the regulated TOU rate, or a non-TOU retail rate. There is substantial variation in when each LDC initially received interval data (smart meter data) and how long until we reached the maximum sample size. For example, in the central region, data for Toronto Hydro begin in January of 2008, but we do not reach the maximum sample size until the middle of 2011. By contrast data for Newmarket-Tay Power begin in July of 2008 and is available almost immediately for the full sample. Figures 4.3 through Figure 4.6 show how many residential customers were on TOU and were not on TOU at any given point in time. The figures below show how the residential sample size changes over the study period for each region. The dotted lines indicate the total number of AMI customers in the sample before TOU; the solid line indicates the total number of AMI customers in the sample on TOU.

Figure 4.3: Central Region TOU Roll-Out

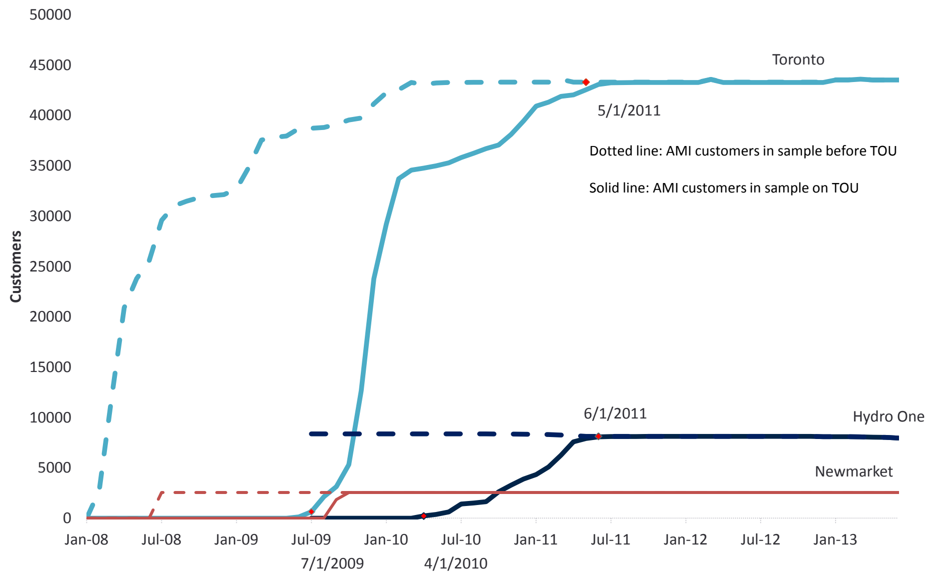


Figure 4.4: East Region TOU Roll-Out

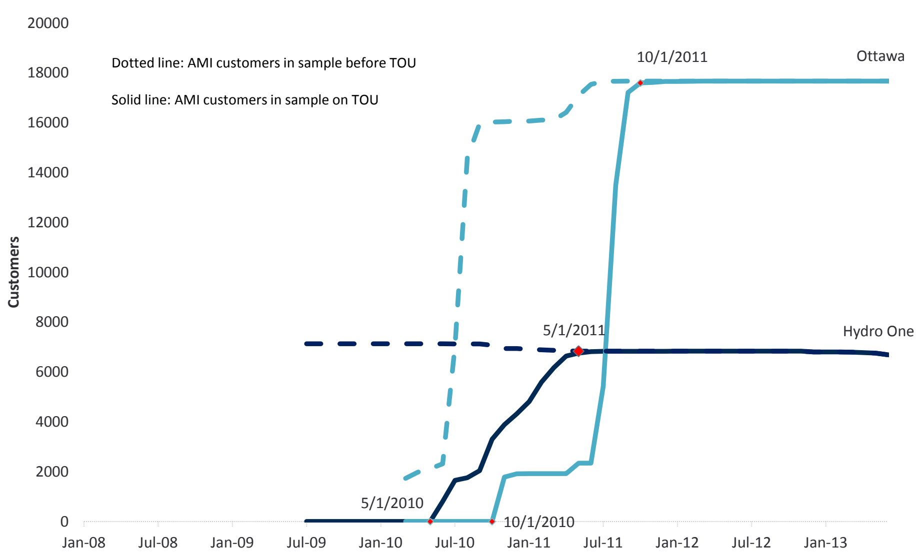


Figure 4.5: West Region TOU Roll-Out

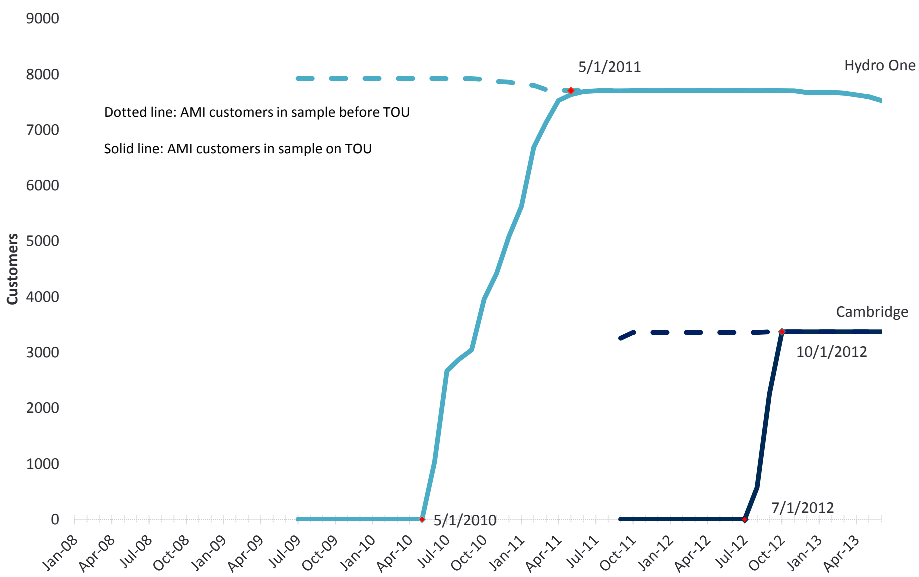
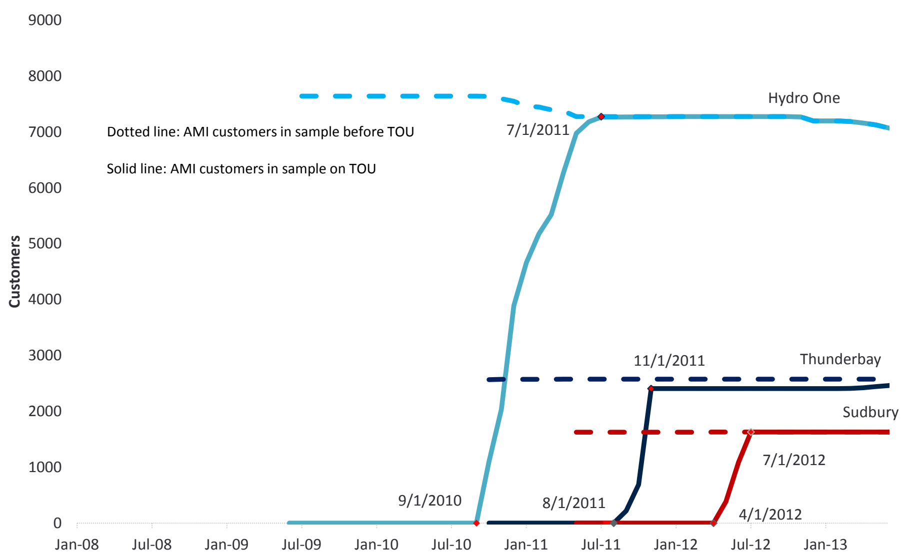


Figure 4.6: North Region TOU Roll-Out



For simplicity of exposition we exclude retail customers and general service customers from this graphical depiction. There may be concerns with whether customers who "self-select" into retail rates are different from other customers and whether customers opted in to retail rates as a direct consequence of TOU rates. We analyzed self-selection among retail customers in the first year of the study and found that it was not a significant concern. In addition we account for self-selection by first differencing observations, thereby removing any fixed differences between customers.[28]

C. Moving from Theory to Application

The addilog model is run separately for each region and each season (summer, winter and OPA peak). The conservation model is run separately for each region, but captures seasonal variation in its parameters.

To obtain elasticities from both models that are representative of the region's population rather than the sample, we estimate price elasticities that are dependent on socio-demographic factors, captured through our price principal components. To get the population elasticity we simply need to substitute in the price principal components that are representative of the population of the region. This allows us to obtain representative price (and weather elasticities) for each of the four regions. To obtain the provincial elasticities we then use the customer count weighted averages of the regional impacts.

To move from elasticities to impact measures, we need to apply those elasticities to a model that has pre-TOU baseline usage and TOU and non-TOU prices for all years. Since the addilog and conservation models are run at the regional level, these quantities need to also be calculated at the regional level. Since each LDC started TOU at a different point in time, each LDC has a different pre-TOU baseline period. These are shown in Figure 4.7.

To get average regional pre-TOU baseline usage we need to take a weighted average of usage for each LDC in the region. Since each LDC has a different baseline year, we wanted to standardize the pre-TOU usage as much as possible. To this end, we use our regression coefficients for weather to remove baseline year weather impacts and replace them with 2011 weather impacts for all LDCs. The year 2011 was selected since it was the first year for which all LDCs had data and was also before the OPA's main period of interest for the study – calendar years 2012, 2013 and 2014.

[28] We are assuming that self-selection is occurring due to unchanging customer factors. Time variable factors that influence self-selection will not be accounted for here.

Figure 4.7: Pre-TOU Base Year Time Periods

LDC	Pre TOU Period From	Pre TOU Period To
Central		
Toronto Hydro	January-09	December-09
Newmarket-Tay Power	July-08	August-09
Hydro One	July-09	June-10
West		
Hydro One	July-09	June-10
Cambridge North Dumfries Hydro	September-11	August-12
East		
Hydro Ottawa	March-10	February-11
Hydro One	July-09	June-10
North		
Thunder Bay Hydro	October-10	September-11
Hydro One	July-09	September-10
Sudbury Hydro	January-10	December-10

V. Results

A. Overview

The analysis is conducted at the regional level and aggregated to the provincial level. Load shifting impacts are split into three separate periods: pre-2012, 2012 and 2013. The pre-2012 period reflects all of the years that LDCs within a region were on TOU rates prior to 2012. Some LDCs started TOU as early as 2009, while others only began in 2012, resulting in compositional changes potentially affecting the comparison between pre-2012 and later years. By the end of 2012, all LDCs in the study were on TOU rates.

For each of the regions we estimated load shifting impacts, energy conservation impacts, and conservation and substitution elasticities. This was separately done for the summer, winter and OPA peak demand months (June, July & August). Overall, the load shifting model parameters have the expected signs and have magnitudes that have been observed in previous pilots. We find that residential customers show more consistent patterns of load shifting behavior than general service customers and that general service customers are less responsive to the TOU prices than residential customers. These results are consistent with findings from other studies.[29] There are however some unexpected positive elasticities in the conservation models. None of these are statistically significant. This is most likely due to the little variation in the overall monthly prices that customers face.

B. RESIDENTIAL RESULTS

Overall, we find that there is significant evidence of load shifting across all LDCs for residential customers, with reductions in usage in the on-peak and mid-peak periods and increases in the off-peak periods. In summer the on-peak reductions are greater than those in the mid-peak periods (in percentage terms), but this differential is somewhat narrowed in winter.

Figure 5.1 summarizes the impacts and substitution elasticities for the summer and winter rate periods, as well as the OPA peak period. The figure also shows the 95 percent confidence interval (C.I.) for the impacts. A 95 percent confidence interval for the estimated impact means that if random samples are drawn repeatedly, the unknown population value for the estimated impact would lie in the lower and upper bound interval for 95 percent of the samples.

For each region load shifting is higher in the summer rates period than the winter. The summer rates period extends from the start of May until the end of October, with the peak being from 11am until 5pm. The winter rates period extends from the start of November through to the end of April with peaks at 7-11am and 5-7pm. The OPA peak demand period occurs in the months of June, July and August between 1 and 7pm. During the summer on-peak period, we estimated that TOU rates induced impacts of -1.6% to -3.5% percent, depending on the region and year. Winter on-peak impacts ranged from -0.2% to -3.1%. During the OPA peak impacts ranged from 0.06% to -3.1%. There was no evidence of conservation, with all estimates showing conservation elasticities that were statistically indistinguishable from zero. The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage during the period in question.

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29 For a review of similar studies see Faruqui A, & S Sergici (2010): "Household Response to Dynamic Pricing of Electricity: A Survey of 15 Experiments", *Journal of Regulatory Economics*, Vol.38, pp.193-225

Figure 5.1: Residential Substitution Impacts

	Pre 2012				2012				2013			
	Impact	95% C.I. for Impact		Substitution Elasticity	Impact	95% C.I. for Impact		Substitution Elasticity	Impact	95% C.I. for Impact		Substitution Elasticity
		Lower Bound	Upper Bound			Lower Bound	Upper Bound			Lower Bound	Upper Bound	
OPA Peak Demand Period (June, July, August 1-7pm)												
North	-2.52%	-2.78%	-2.26%	-0.16	-1.16%	-1.56%	-0.75%	-0.08	0.06%	-0.67%	0.79%	-0.03
Central	-1.26%	-1.35%	-1.17%	-0.10	-1.48%	-1.83%	-1.11%	-0.11	-0.32%	-0.85%	0.22%	-0.06
East	-2.33%	-2.50%	-2.15%	-0.15	-3.12%	-3.57%	-2.65%	-0.18	-2.93%	-3.71%	-2.14%	-0.16
West	-2.41%	-2.69%	-2.13%	-0.14	-1.84%	-2.20%	-1.46%	-0.11	-0.19%	-0.75%	0.37%	-0.04
Province	**-1.85%**	-2.02%	-1.68%	-0.13	**-1.82%**	-2.19%	-1.43%	-0.12	**-0.68%**	-1.28%	-0.08%	-0.07
Summer Peak Period (11am - 5pm)												
North	-3.37%	-3.59%	-3.15%	-0.16	-2.09%	-2.40%	-1.78%	-0.10	-1.60%	-2.17%	-1.01%	-0.08
Central	-2.56%	-2.64%	-2.48%	-0.13	-1.85%	-2.15%	-1.53%	-0.10	-2.57%	-3.02%	-2.11%	-0.12
East	-3.07%	-3.23%	-2.92%	-0.15	-2.61%	-2.99%	-2.22%	-0.13	-2.91%	-3.56%	-2.25%	-0.14
West	-3.48%	-3.69%	-3.26%	-0.17	-2.54%	-2.81%	-2.26%	-0.13	-1.63%	-2.08%	-1.19%	-0.09
Province	**-2.96%**	-3.10%	-2.82%	-0.15	**-2.18%**	-2.49%	-1.87%	-0.11	**-2.29%**	-2.78%	-1.79%	-0.11
Winter Peak Period (7 - 11am)												
North	-2.47%	-2.61%	-2.34%	-0.11	-1.17%	-1.37%	-0.96%	-0.05	-2.02%	-2.39%	-1.65%	-0.08
Central	-1.47%	-1.52%	-1.41%	-0.07	-0.61%	-0.81%	-0.41%	-0.03	-0.21%	-0.52%	0.11%	-0.02
East	-3.08%	-3.18%	-2.97%	-0.15	-2.01%	-2.26%	-1.76%	-0.09	-1.81%	-2.24%	-1.38%	-0.08
West	-2.38%	-2.54%	-2.23%	-0.12	-1.61%	-1.81%	-1.41%	-0.08	-1.31%	-1.63%	-0.99%	-0.06
Province	**-2.06%**	-2.16%	-1.97%	-0.10	**-1.16%**	-1.36%	-0.95%	-0.06	**-0.92%**	-1.25%	-0.57%	-0.05
Winter Peak Period (5 - 7pm)												
North	-2.15%	-2.28%	-2.01%	-0.10	-0.81%	-1.00%	-0.61%	-0.04	-1.63%	-2.00%	-1.25%	-0.07
Central	-2.09%	-2.14%	-2.03%	-0.10	-1.25%	-1.44%	-1.04%	-0.06	-0.87%	-1.17%	-0.55%	-0.04
East	-2.30%	-2.40%	-2.20%	-0.11	-1.20%	-1.45%	-0.95%	-0.06	-0.90%	-1.33%	-0.46%	-0.05
West	-1.84%	-1.99%	-1.69%	-0.09	-1.02%	-1.21%	-0.84%	-0.05	-0.67%	-0.99%	-0.35%	-0.04
Province	**-2.06%**	-2.15%	-1.96%	-0.10	**-1.14%**	-1.34%	-0.94%	-0.06	**-0.88%**	-1.22%	-0.54%	-0.04

Figure 5.2 shows the impacts for the OPA peak demand period (which is not the same as the TOU period seen by consumers), which is calculated over June, July and August from 1 to 7pm. The colored bars show the estimated impacts, while the black brackets show a 95 percent confidence interval for the impact. In the pre-2012 and 2012 periods the confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be fairly confident that we can reject the null hypothesis of zero-load shifting in these years. However load shifting is substantially lower in 2013 in all regions except the East. For the province as a whole there was a statistically significant reduction in usage during the OPA peak of 1.85 percent in the pre-2012 period, 1.82 percent in 2012 and 0.68 percent in 2013 relative to what usage would have been in the absence of TOU.

Figure 5.2: Residential OPA Peak Impacts (June July, August, 1PM – 7PM)

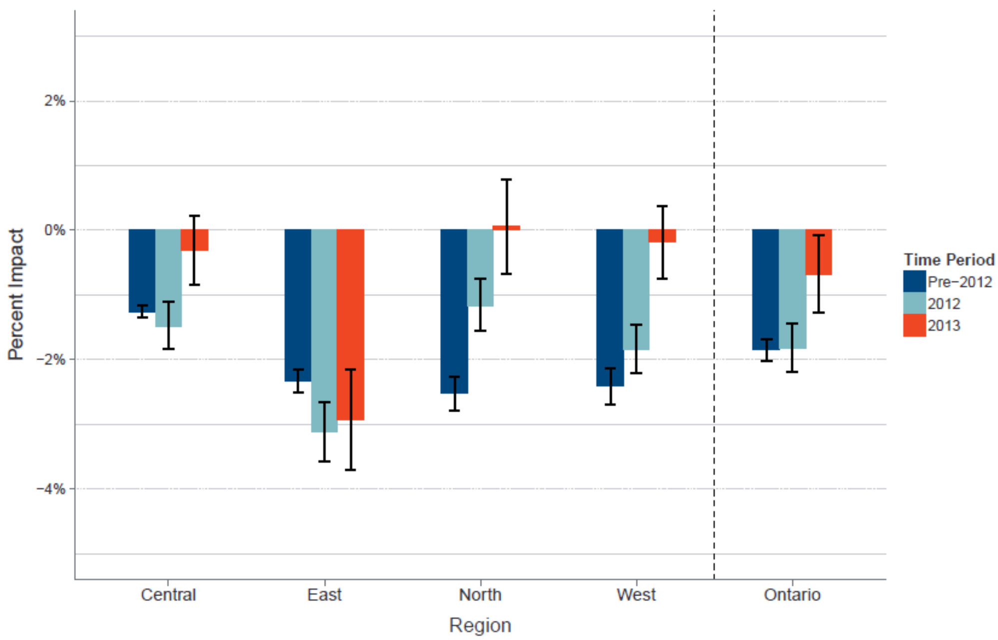
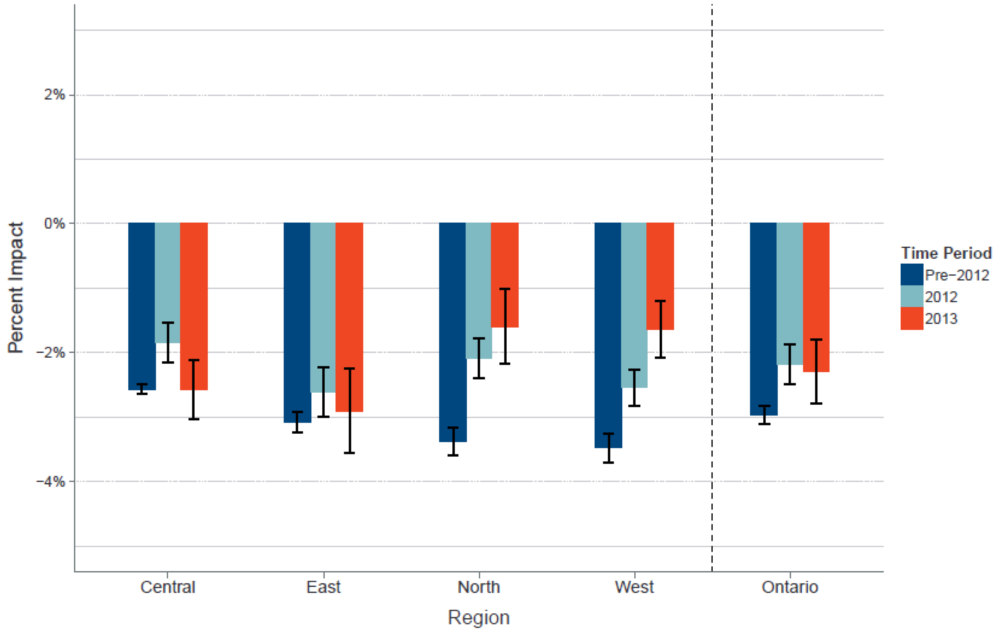


Figure 5.3 shows the impacts during the summer on-peak period across the regions and province for residential customers. The confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be fairly confident that we can reject the null hypothesis of zero load-shifting in all years and regions. For the province as a whole, TOU reduced usage during the summer on-peak period by 2.96 percent in the pre-2012 period, 2.18 percent in 2012 and 2.29 percent in 2013, relative to what usage would have been in the absence of TOU.

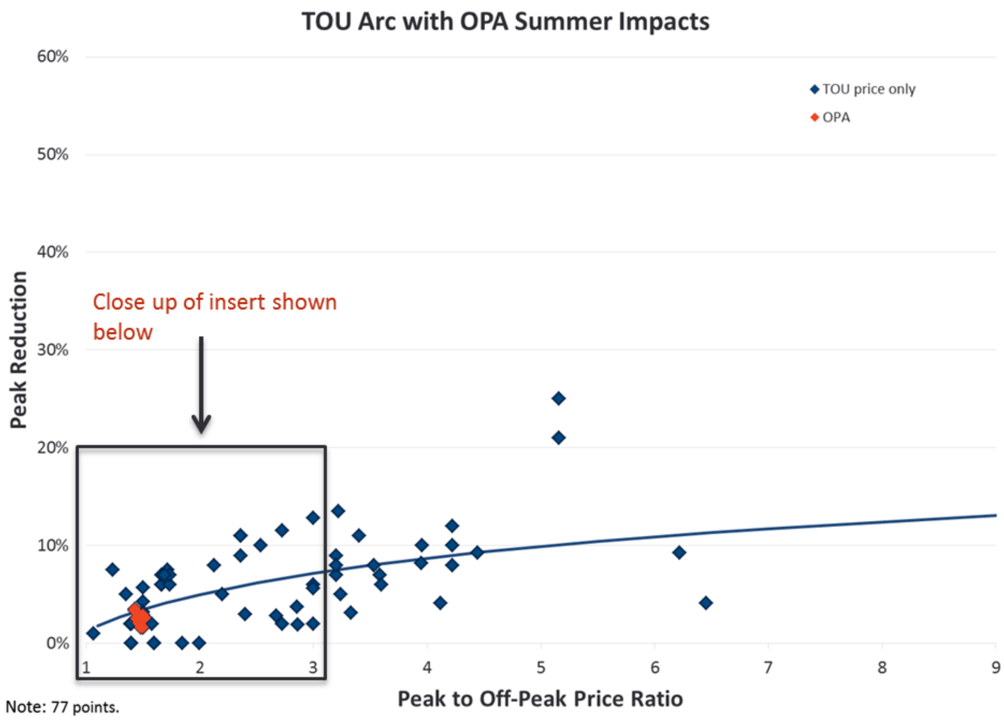
It is unclear from the data available to us why customer response dipped in the inner summer months of the 2013 OPA peak demand period, but not for the summer as a whole, especially since all of the data is weather normalized.

Figure 5.3: Residential TOU Summer On-Peak Period Impacts (11am – 5pm)



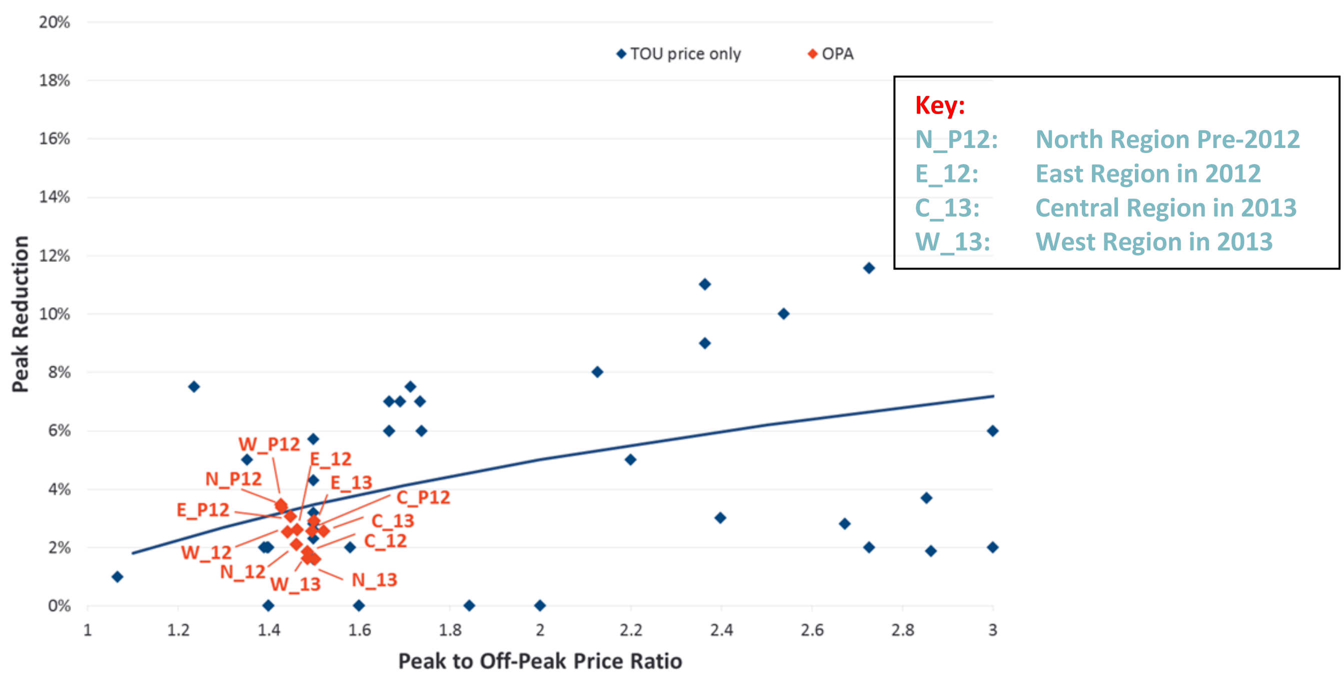
Figures 5.4a and 5.4b compare the Ontario residential summer TOU on-peak period results to results collected from 77 pilots around the world using The Brattle Group's Arcturus database. The OPA impacts are the only impacts reported in both figures obtained from a full scale roll-out rather than a pilot. On the y-axis is the percentage peak reduction, while the x-axis shows the peak to off-peak price ratio. The blue curve is Brattle's Arc of price responsiveness, which is an econometric estimation of the curve that best fits the data. The Arc can be used to make predictions of peak reductions for various peak to-off peak price ratios. In Ontario the peak-to-off peak price ratio for all of the LDCs was approximately 1.5. This would correspond to a 3 percent reduction in peak usage, which is slightly higher than the estimates made in each region in 2012 and 2013. The lower bound of the 95 percent confidence bound on the impacts for these years were 2.49 and 2.78 percent respectively.

Figure 5.4a: Ontario Residential TOU Impacts Compared to TOU Pilots from around the World



Note: 77 points.
Source: Faruqui, Ahmad. "Arcturus." The Brattle Group.

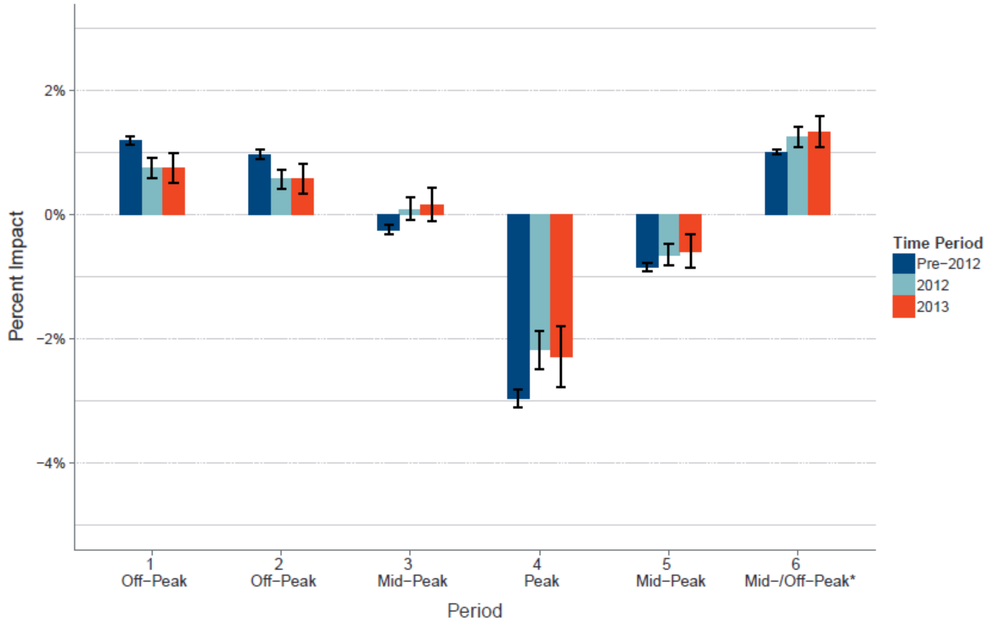
Figure 5.4b: Close up of Ontario Residential TOU Impacts Compared to TOU Pilots from around the World with Peak to Off-Peak Price Ratios



Source: Faruqui, Ahmad. "Arcturus." The Brattle Group.

Figure 5.5 shows residential load shifting across all periods in the summer for the whole province. Period 1 is weekends and holidays which are off-peak. Period 2 is from 9pm to 7am and is also off-peak. Period 3 is from 7am to 11am and is mid-peak. Period 4 is the on-peak period from 11am to 5pm. Period 5 is the second mid-peak from 5pm to 7pm. Period 6 from 7pm to 9pm is currently off-peak, but was mid-peak before May of 2011. Load is effectively shifted from the on-peak and evening mid-peak period to the off-peak periods. There is no change in load during the morning mid-peak period.

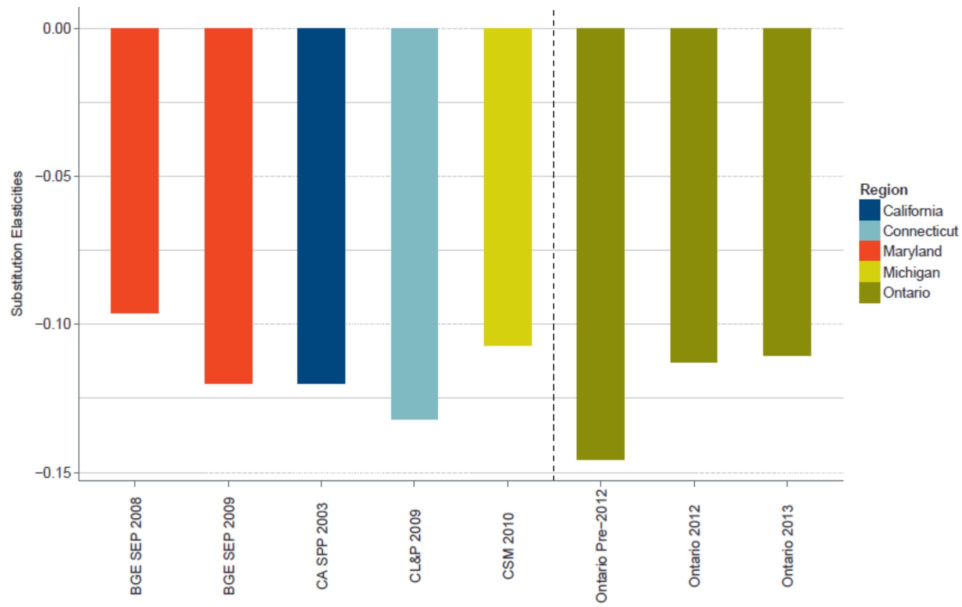
Figure 5.5: Province-Level Residential Loadshifting in the Summer



Finally we estimated substitution and overall conservation elasticities. A substitution elasticity indicates the percent change in the ratio of peak-to-off-peak consumption due to 1 percent change in the peak-to-off-peak price ratio. For instance, a substitution elasticity of -0.10 implies that, when the peak-to-off-peak price ratio increases by 1 percent, the usage ratio decreases by 0.10 percent. Overall conservation elasticities indicate the percent change in the average monthly consumption due to a 1 percent change in the average monthly price. For instance, an overall conservation elasticity of -0.05 implies that, when the average monthly price increases by 1 percent, the average monthly usage decreases by 0.05 percent.

Figure 5.6 shows substitution elasticities from several other studies alongside the provincial residential summer on-peak elasticities. The provincial elasticities, which lie between -0.1 and -0.15, are shown on the right. Altogether, they are very similar in magnitude to elasticities observed in other studies.

Figure 5.6: Residential Substitution Elasticities compared to Other Pilots (summer peak period)[30]



We did not find any statistically significant evidence of conservation in the residential class across all regions and do not report a conservation elasticity for the residential class. Figure 5.7 shows the average monthly TOU and non-TOU all in prices that consumers face from 2010 to 2013 split by region. Within each region the TOU and non-TOU prices track each other closely and there is little overall price variation.

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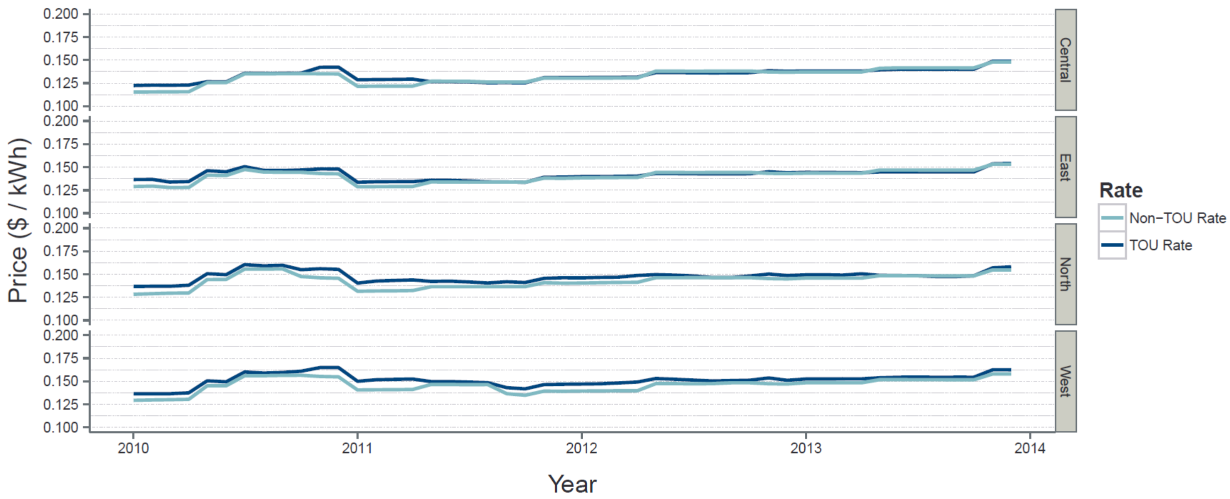
30 Data drawn from several studies, see respectively:

1) Faruqui, A. & S. Sergici (2009): "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment", *Journal of Regulatory Economics*, Vol. 40(1), pp 82-109
2) A Faruqui and S. George (2005)"Quantifying Customer Response to Dynamic Pricing", *The Energy Journal,* Vol. 18(4), pp. 53–63
3) Faruqui, A, Sergici, S. and L. Akaba (2014): "The Impact of Dynamic Pricing on Residential and Small Commercial and Industrial Usage: New Experimental Evidence from Connecticut", *The Energy Journal",* Vol. 35(1), pp.137-161
4) Faruqui, A, Sergici, S. and L. Akaba (2013): "Dynamic pricing of electricity for residential customers: the evidence from Michigan", *Energy Efficiency,* Vol. 6(3), pp. 571-584

Figure 5.7 Residential TOU and Non-TOU Prices 2010-2013



Detailed information and impact estimates for each region can be found in the Appendix to this report.

C. General Service Results

Overall we find that there is some evidence of load shifting across all regions for general service customers, with reductions in usage in the on-peak and mid-peak periods and small increases in the off-peak periods. Impacts are far smaller than those estimated for the residential customer class , results are not as unambiguous, and there are some odd substitution patterns. This is most likely an artifact of the heterogeneity in the General Service class.

During the OPA peak demand period across all regions and years, we estimated that TOU rates induced impacts ranged from 0.6% to -3.3%. During the TOU summer on-peak period, we estimated that TOU rates induced impacts of 0.5% to -2.7% percent, depending on the region and year. Winter on-peak impacts ranged from 0.7% to -1.6%, again varying by region and year. Evidence on conservation was limited, with all estimates showing very small (less than 0.5%) conservation impacts.

Figure 5.8 summarizes the impacts and substitution elasticities for the summer and winter rates period, as well as the OPA peak period for the General Service class. Unlike for the residential class, there is no clear pattern of winter versus summer load shifting impacts.

Figure 5.8: Summary of General Service Impacts and Elasticities during the Peak Period

	Pre 2012				2012				2013			
	Impact	95% C.I. for Impact		Substitution Elasticity	Impact	95% C.I. for Impact		Substitution Elasticity	Impact	95% C.I. for Impact		Substitution Elasticity
		Lower Bound	Upper Bound			Lower Bound	Upper Bound			Lower Bound	Upper Bound	
OPA Peak Demand Period (June, July, August 1-7pm)												
North	-0.58%	-1.16%	-0.01%	-0.04	-1.25%	-2.00%	-0.47%	-0.08	-3.30%	-4.69%	-1.87%	-0.18
Central	-1.27%	-1.93%	-0.62%	-0.07	-0.20%	-1.18%	0.83%	-0.03	0.14%	-2.02%	2.28%	-0.01
East	-0.15%	-0.54%	0.24%	-0.03	0.42%	-0.36%	1.22%	0.00	0.62%	-0.82%	2.09%	0.01
West	-0.54%	-1.05%	-0.03%	-0.03	-0.08%	-0.73%	0.56%	-0.01	-0.05%	-1.21%	1.08%	-0.02
Province	**-0.82%**	-1.38%	-0.27%	-0.05	**-0.17%**	-1.00%	0.69%	-0.02	**-0.17%**	-1.51%	1.21%	-0.03
Summer Peak Period (11am - 5pm)												
North	-0.81%	-1.30%	-0.32%	-0.04	-1.13%	-1.71%	-0.53%	-0.06	-2.65%	-3.76%	-1.55%	-0.13
Central	-1.09%	-1.64%	-0.55%	-0.05	-0.28%	-1.09%	0.56%	-0.03	-1.85%	-3.58%	-0.12%	-0.10
East	-0.21%	-0.53%	0.11%	-0.03	0.48%	-0.14%	1.13%	0.00	0.03%	-1.13%	1.21%	-0.02
West	-0.58%	-1.03%	-0.13%	-0.02	-0.15%	-0.68%	0.40%	-0.01	-0.61%	-1.60%	0.35%	-0.04
Province	**-0.78%**	-1.26%	-0.32%	-0.04	**-0.21%**	-0.88%	0.50%	-0.02	**-1.28%**	-2.50%	-0.10%	-0.07
Winter Peak Period (7 - 11am)												
North	-0.48%	-0.78%	-0.19%	-0.02	-0.45%	-0.78%	-0.12%	-0.03	-0.33%	-0.95%	0.30%	-0.02
Central	-0.57%	-0.90%	-0.26%	-0.01	-0.12%	-0.61%	0.39%	-0.02	-1.44%	-2.50%	-0.36%	-0.07
East	-0.37%	-0.54%	-0.20%	-0.03	-0.58%	-0.95%	-0.20%	-0.03	-1.29%	-1.99%	-0.57%	-0.06
West	-0.37%	-0.68%	-0.07%	-0.01	-0.46%	-0.79%	-0.12%	-0.02	0.61%	-0.03%	1.25%	0.02
Province	**-0.47%**	-0.76%	-0.20%	-0.01	**-0.32%**	-0.72%	0.10%	-0.02	**-0.74%**	-1.58%	0.12%	-0.04
Winter Peak Period (5 - 7pm)												
North	-0.38%	-0.68%	-0.08%	-0.02	-0.34%	-0.66%	-0.01%	-0.02	-0.27%	-0.89%	0.36%	-0.02
Central	-0.73%	-1.04%	-0.41%	-0.02	-0.28%	-0.75%	0.21%	-0.03	-1.64%	-2.70%	-0.56%	-0.08
East	0.13%	-0.04%	0.29%	0.00	-0.08%	-0.44%	0.30%	-0.01	-0.75%	-1.45%	-0.03%	-0.04
West	-0.26%	-0.56%	0.04%	0.00	-0.33%	-0.66%	0.01%	-0.02	0.74%	0.10%	1.39%	0.02
Province	**-0.43%**	-0.71%	-0.15%	-0.01	**-0.27%**	-0.66%	0.14%	-0.02	**-0.70%**	-1.55%	0.15%	-0.04

Figure 5.9 shows General Service impacts during the OPA peak demand period across all regions and years. The confidence bands are wide relative to the magnitude of the impacts and we cannot confidently reject the null hypothesis of no load shifting in most of the regions and years. For the province as a whole only the pre-2012 impact is statistically distinguishable from zero.

Figure 5.9: General Service OPA Peak Impacts (June, July, August, 1pm – 7pm)

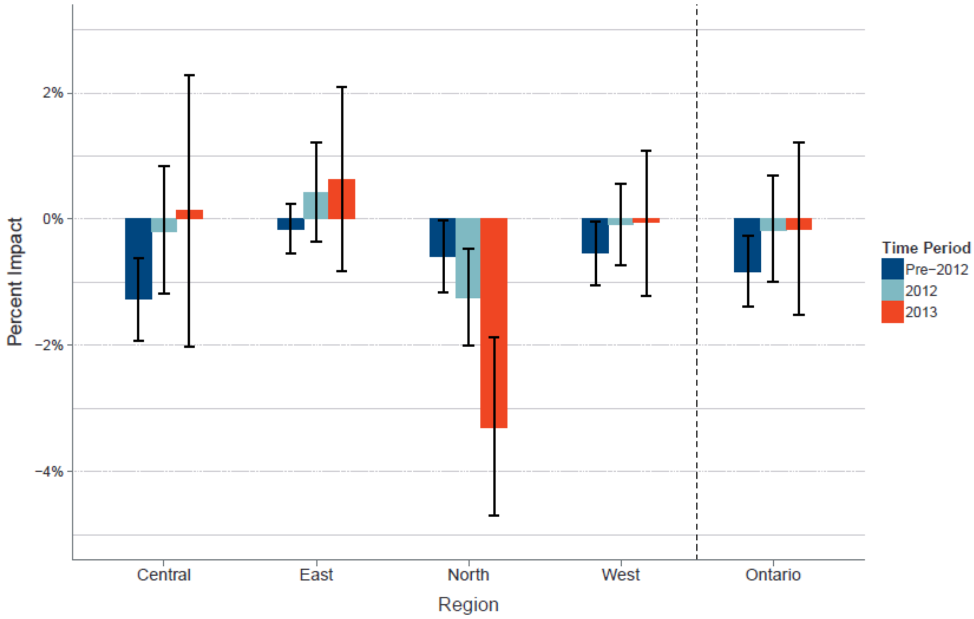


Figure 5.10 shows General Service impacts during the summer on-peak period across all regions and years. Again confidence bands are wide relative to the magnitude of the impacts and we cannot confidently reject the null hypothesis of no load shifting in most of the regions and years. For the province as a whole, both the pre-2012 and 2013 impacts are statistically distinguishable from zero.

Figure 5.10: General Service Summer On-Peak Period Impacts (11am – 5pm)

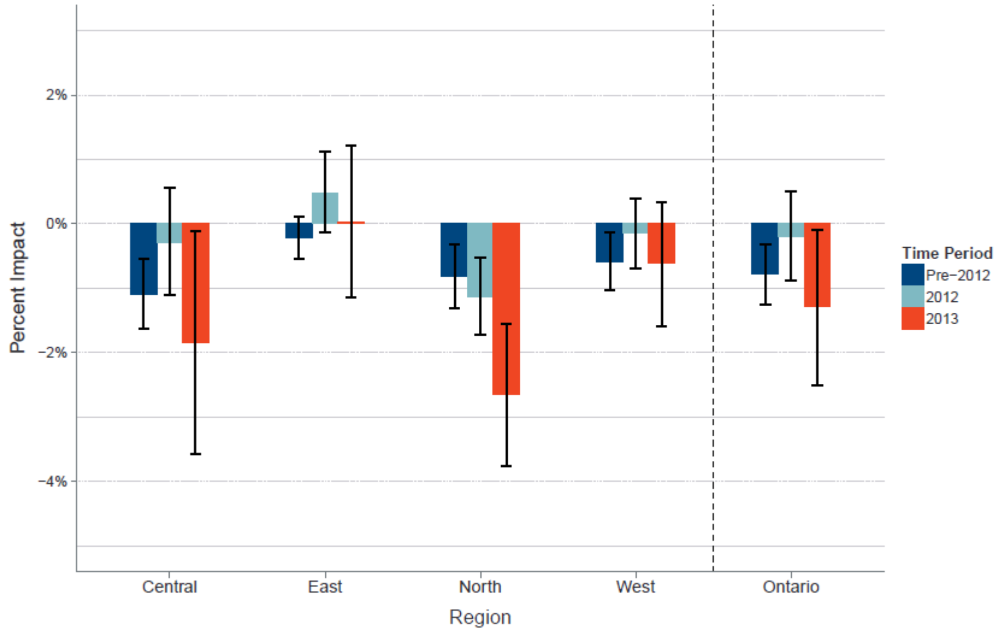
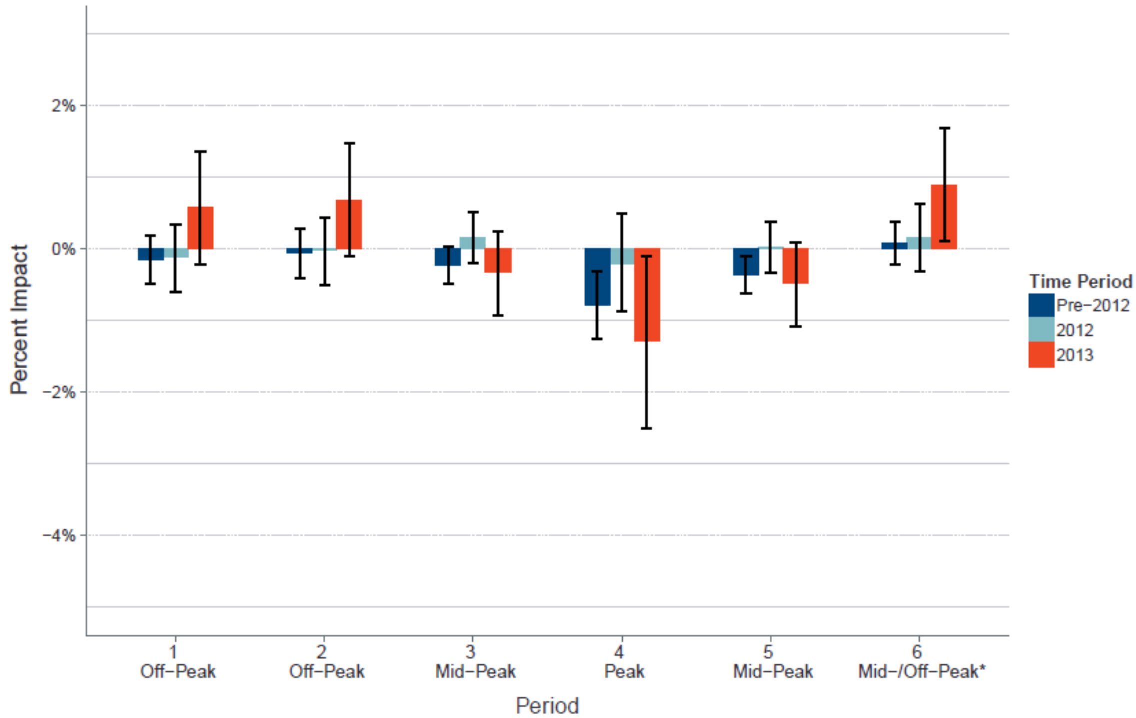


Figure 5.11 shows general service load shifting across all periods in the summer for the whole province. Period 1 is weekends and holidays which are off-peak. Period 2 is from 9pm to 7am and is also off-peak. Period 3 is from 7am to 11am and is mid-peak. Period 4 is the on-peak period from 11am to 5pm. Period 5 is the second mid-peak from 5pm to 7pm. Period 6 from 7pm to 9pm is currently off-peak, but was mid-peak before May of 2011. There is no clear pattern of load shifting from peak to off-peak periods.

Figure 5.11: Province-Level General Service Loadshifting in the Summer



Detailed information and impact estimates for each region can be found in the Appendix to this report.

VI. Challenges and Limitations

In this section, we describe the challenges and limitations of this study and our approach to overcoming them, where feasible.

1. Full-scale deployment of TOU rates poses two challenges for the impact evaluation:
   a. The TOU roll-out was not designed as a randomized controlled experiment and there is no control group. In the first year of the study, we were able to exploit the phased nature of the deployment within the LDCs to construct a proxy control group. We allocated the eligible customer lists into two groups using the median TOU start date. Customers who got the TOU rates after the median date were classified in the "potential control group" bucket, whereas the customers who got the rates before this date were placed in the "potential treatment group" bucket. After determining the sample sizes, we randomly selected the control and treatment groups from these two buckets. In the second year study we examine impacts in 2012 and 2013, when almost all customers are on TOU rates.

Fortunately there is still a small pool of retail customers to act as a control group. In addition we have the pre-2012 results to act as a check on the later results, since these results are calculated as incremental divergences from the pre-2012 results.

b. For some LDCs, the TOU rates were deployed very shortly after the AMI deployment. This implies that there is a very short window with pre-TOU data available. We address this issue in the sample design process by defining eligible customers to be included in the study as those who have at least 6 months of pre-TOU and at least 12 months of post-TOU data.

2. We use a small group of retail customers as an additional control group as some LDCs complete the TOU deployment too quickly. There may be a concern that those customers who "self-select" into the retail rates may be different from other customers, particularly if they do so as a reaction to TOU rates. In order to account for this potential self-selection bias, we run our regressions using first differences ($year_t - year_{t-1}$) to remove any customer specific characteristics that do not change over time. If there is a specific customer attribute that prompts them to select into the retail rate, this attribute will be removed by taking the first differences. For example if customers have higher than average usage in the peak periods, this usage pattern will be removed by taking the difference between the current and previous year. Moreover, if customers opted out of TOU because they anticipated their usage becoming peakier, we would find larger negative elasticities than we should and in such a case we would be overstating the TOU impacts. In the first year study we tested whether self-selection by retail customers biased our results downward and found no evidence to support this.

3. Little overall price variation led to difficulties with conservation equations and resulted in implausible (i.e. positive) conservation elasticities primarily for residential customers. None of these elasticities are statistically distinguishable from zero. We therefore zeroed out these implausible conservation elasticities for impact calculations.

4. Due to data availability issues, we were not able to include general service class customers from Toronto Hydro and Newmarket-Tay Power

5. The Newmarket-Tay Power sample was not drawn using the procedure for the other LDCs due to data availability problems. Therefore it may not be representative of the relevant population.

6. We were unable to include retail customers for Sudbury Hydro. These will be included in the final year of the study.

7. While we correct for serial correlation of the error term in the monthly consumption model, we were unable to do so for the addilog system which estimates the load shifting

impacts because of time constraints. Under a certain set of assumptions, we have correctly estimated the standard errors. We plan to incorporate a correction for serial correlation in the addilog system in the final year of this study. However, to get a rough idea of the imprecision in the standard error estimates, we have run a few simulations and concluded that the standard errors in the addilog estimation may be understated by a factor of two. Using this rule of thumb, we still find that the estimated impacts would be statistically significant at the 95 percent confidence level.

VII. Conclusions and Next Steps

The Second Year Study of Ontario's Full-scale TOU Program revealed that the residential customers responded to the TOU rates by shifting their usage from peak to off-peak and mid-peak periods and have magnitudes that have been observed in pilots. Load shifting during the OPA peak demand period was lower in 2013 than in previous years despite peak period load shifting for the entire summer period being of a similar magnitude to previous years. The load shifting impacts for general service customers were far smaller than those estimated for the residential customer class and results are not as distinct, with some odd substitution patterns. This is most likely an artifact of large variability in customers that comprise the general service class. Evidence on energy conservation was non-existent for residential customers and negligible and generally insignificant for the general service class.

The Second Year Study involved some challenges mostly in the process of data compilation. This was despite the adoption of many of the recommendations from the First Year Study intended to streamline the process. The analysis also involved some methodological challenges due to the heterogeneity in the timing of the TOU deployments and the resulting difficulties associated with defining comparable impacts across all LDCs. We have overcome these challenges by carefully crafting our methodology.

In the Final Study Year, we will build upon the strong foundation established in this study, adding one more year of data and PowerStream customers' data to the study. This will allow us to estimate final representative provincial TOU impact estimates for 2012, 2013 and 2014.

GLOSSARY

Addilog Demand System: it is a well-behaved demand system which is capable of estimating small elasticities of substitution. Unlike more flexible demand systems, the Addilog System satisfies regularity conditions (e.g., concavity) globally.

Constant Elasticity of Substitution System: is a well-behaved demand system which allows the elasticity of substitution to take any value. The CES model has been found to be well-suited to TOU pricing studies involving electricity since there is strong prior evidence suggesting that these elasticities are going to be small.

Cooling Degree Humidex Index: is a warm weather indicator defined as follows,

$$CDHM_t = \max\left[HM_t - 22{,}0\right]$$

$$where \quad HM_t = \max\left[H_t \cdot d_t, T_t\right] \quad with \quad d_t = \begin{cases} 1\ if\ \ H_t\ is\ reported \\ \quad 0\ otherwise \end{cases}$$

T_t is hourly outdoor air temperature at hour t .

Difference-in-Differences Estimation: is a technique to measure the effect of a treatment by first calculating the difference between pre and post treatment periods for the treatment group and then netting it off by the difference between these two periods for the control group.

General Service Customer: are non-residential customers with demands less than 50 kW

Heating Degree Wind-Chill Index: is a cold weather indicator defined as follows,

$$HDW_t = max[18 - W_t, 0]$$

with $W_t = min[T_{wct} \cdot v_t, T_t]$ with $v_t = \begin{cases} 1\ if\ T_{wct}\ is\ reported \\ \quad otherwise \end{cases}$

T_t is hourly outdoor air temperature at hour t , and

T_{wct} is the wind chill statistic reported by Environment Canada.

Price Elasticity of Demand: represents the percentage change in quantity demanded in response to a one percent change in price holding constant all the other determinants of demand.

Randomized Control Experiment: in randomized controlled experiments, eligible customers are randomly allocated into the treatment and control groups. The treatment customers receive the treatment (TOU rates in this context), whereas the control customers do not receive the treatment.

Residential Service Customer: refers to single family homes and individually metered apartment buildings. When the metering takes place at the building level, they are classified as general service customers.

Seemingly Unrelated Regression: is a generalization of a linear regression model that consists of several regression equations, each having its own dependent variable and potentially different sets of exogenous explanatory variables. Each equation is a valid linear regression on its own and can be estimated separately, which is why the system is called *seemingly unrelated*, although some authors suggest that the term *seemingly related* would be more appropriate, since the errors are assumed to be correlated across the equations.

Substitution Elasticity: indicates the percent change in the ratio of peak-to-off-peak consumption that occurs due to a one percent change in the peak-to-off-peak price ratio. For instance, a substitution elasticity of -0.10 implies that, when the peak to off-peak price ratio increases by 1%, the corresponding peak to off-peak usage ratio decreases by 0.10%. Or put another way, if the peak to off-peak price ratio was to be doubled, the corresponding usage ratio would fall by 10%.

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