An Overall Assessment of the Responsiveness of Households to Time-of-Use Electricity Rates: The Ontario Experiment

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From 1982 to 1988, Ontario Hydro implemented a residential rate experiment. This paper provides a discussion of results obtained from econometric models which to date have yielded information on the experimental changes in residential load shapes. The results take the form of elasticities, percentage impacts, load changes at the household level and simulated province-wide load changes. The paper includes comparisons of results with other jurisdictions, comparisons of impacts on households with and without electric heating and with and without air conditioning, and comparisons across rate treatments with varying lengths of peak periods and relative prices. A fundamental conclusion is that time-of-use electricity rates do make a difference in residential load shapes.

Entre 1982 et 1988, Hydro Ontario a expérimenté l'application d'un tarif résidentiel. Cet article fournit une discussion des résultats obtenus à partir de modèles économétriques qui jusqu'ici ont servi à recueillir l'information sur les changements expérimentaux dans les formes de la charge résidentielle. Les résultats prennent la forme d'élasticités, d'impacts en pourcentage, de changements de la charge au niveau du foyer et des changements simulés de la charge à l'échelle de la province. Cet article inclut des comparaisons de résultats avec d'autres juridictions, des comparaisons d'impact sur les foyers avec ou sans chauffage électrique et avec ou sans air conditionné, et des comparaisons tenant compte de l'échantillonnage des taux en fonction des variations de la longueur des périodes de pointe et des prix relatifs. Une conclusion fondamentale est que les taux de facturation de l'énergie électrique qui sont fonction de l'heure d'utilisation font une différence quant aux formes de la charge résidentielle.

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1. Introduction

One of the most important criteria for determining whether a utility adopts time-of-use rates (whether it be mandatory or voluntary implementation) is the extent to which customers change their load shape in response to a new rate structure. Consider the extreme of time-of-use rate implementation causing no change in load shape. In this case, from the perspectives of efficiency and revenue recovery, the movement away from a one-price average cost structure is pointless.[1] On the other hand, if time-of-use rates cause some significant changes in load shape, we must ask whether the movement would cause enough benefits to offset any implementation costs. What kind of changes in load shape might we see? A movement to higher electricity prices in the winter and lower rates in the summer would probably induce conservation in the winter and increased consumption in the summer. A rise in rates during a peak time period in conjunction with a drop in rates during the off-peak should cause a shifting from peak to off-peak consumption. To learn about such possible changes in load shape in the residential sector, Ontario Hydro conducted a time-of-use rate experiment from 1982 to 1988 with 500 participants. The paper provides an overall assessment of the responsiveness of households during this six-year time-of-use experiment. It consists of a discussion of results obtained from analytical models which to

1/ Of course there may be other considerations for implementation. This may include equity and fairness in allocation of costs.

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date have yielded information on the experimental changes in residential load shapes.[2] While the important results from these models are highlighted, the paper is not comprehensive. Detailed results can be found in specific papers and reports (e.g., See Lawson (1989), Mountain (1990), and Mountain and Lawson (1990, 1992)).

The paper begins with a description of the experiment. Section 3 provides an analytic perspective for measuring load responsiveness. A capsulization of the results is found in section 4 and concluding comments are in Section 5.

2. The Experiment

The Ontario Hydro residential time-of-use experiment began in 1982. Five hundred residential households were selected from 28 municipalities and 11 rural areas. This was a stratified sample based on geography, electric space heating, electric water heating and central air conditioning (see Ontario Hydro (1981) for a discussion of this initial selection). During the first year, from October 1982 to September 1983, the electricity consumption of households was monitored (on a 15 minute basis) while the households were being charged conventional, non-time-differentiated rates. In this first year the households were not informed about being potential participants in a time-of-use rate experiment. In the fall of 1983, all but 66 households were asked to go onto time-of-use rates until the fall of 1988. These 434 households were offered one and only one of 14 time-of-use rate treatments.[3] Each rate cell was distinct from the other with respect to relative prices, seasonality and length of on-peak and off-peak rates. The rates were designed to reflect time variations in future system and distribution costs, both at the bulk and at the municipality level. Table 1 provides a summary of the rate cells and associated relative and absolute prices.

The rate treatments were designed (see Jefferies and Lawson (1985)) to be revenue neutral for an average electric heating household. The load profile for this "average" electric heating household was based on prior load research monitoring of an Ontario subdivision of houses with electric heating. However, any household in the experiment could have a load profile distinct from this "average electric heating" profile. The result is that under time-of-use rates households could be worse or better off in maintaining their baseline load patterns. It was calculated that 46.8% (53.2%) of the participants would have been better (worse) off if they maintained their baseline load profiles under time-of-use rates. No information was provided to the participants on how their load patterns matched up to the reference electric heating household.

Participation in the experiment was voluntary. The participation rate was large; only 8.8% of those offered time-of-use rates decided not to participate. Nevertheless, a question remains regarding potential selectivity biases (see, for example, Aigner and Hausman (1980) for a discussion of such potential biases) attributable to whether households would save or lose money after their participation. Under the baseline pattern, the savings or losses of potential participants was calculated. The magnitude of savings was divided into four categories. No difference was found between the distribution of participants versus non-participants according to their distribution of savings.

The participants were randomly assigned across location, type of heating, presence of electric water heating, household income and dishwasher ownership to one of 17 rate cells (see Jefferies and Lawson (1985)). During the life of the experiment, Ontario Hydro administered a questionnaire on an annual basis to obtain an updated picture of each household's stock of appliances, demographic composition, electricity consumption traits and its attitudes towards time-of-use rates. For their willingness to participate in this annual attitudes/demographic questionnaire households were offered a flat annual payment of $40 (annually adjusted to reflect the overall inflation rate of electricity within a household's municipality or area). This lump sum payment was not tied to either a household's baseline or response patterns, and this fact was made very clear to the participants.

2/ Indeed, as in all research endeavours, by no means can the following results be viewed as final remarks on the participants' responsiveness. Other efforts are being undertaken to refine these estimates, and no doubt other efforts will be made in the future.

3/ The other 66 households were distributed among three non-time differentiated rates. These rate structures include a control declining block-rate structure, flat rate structure with a customer charge and a flat rate structure with no customer charge.

Table 1: Ontario Hydro's Time-of-Use Rates

Rate	Seasons		Time-of-Day[a]	Relative Rates[b]	Absolute Prices (¢/kWh)[c]
0	Annual	Control		1.0	3.76
1	Annual	Control		1.0	3.76
2	Annual	Flat rate (no customer charge)		1.0	3.93
3	Winter - 10-03	Peak	- 07-23 WD	1.8	4.64
		Off-Peak	- 23-07 WD & WE	1.4	3.61
	Summer - 04-09	Peak	- 07-23 WD	1.3	3.35
		Off-Peak	- 23-07 WD & WE	1.0	2.58
4	Winter - 10-03	Peak	- 07-23 WD	3.8	6.11
		Off-Peak	- 23-07 WD & WE	1.4	2.25
	Summer - 04-09	Peak	- 07-23 WD	2.7	4.34
		Off-Peak	- 23-07 WD & WE	1.0	1.61
5	Winter - 10-03	Peak	- 07-23 WD	7.8	7.20
		Off-Peak	- 23-07 WD & WE	2.0	1.85
	Summer - 04-09	Peak	- 07-23 WD	3.9	3.60
		Off-Peak	- 23-07 WD & WE	1.0	0.92
6	Annual	Peak	- 07-23 AD	1.3	4.04
		Off-Peak	- 23-07 AD	1.0	3.11
7	Annual	Peak	- 07-23 WD	3.9	6.09
		Off-Peak	- 23-07 WD & WE	1.0	1.56
8	Winter - 10-03	Peak	- 07-12, 16-21 WD	3.8	7.62
		Off-Peak	- 12-16, 21-07 WD & WE	1.4	2.81
	Summer - 04-09	Peak	- 07-12 WD	2.7	5.42
		Off-Peak	- 12-07 WD & WE	1.0	2.01
9	Winter - 10-03	Peak	- 07-12, 16-21 WD	6.3	12.01
		Off-Peak	- 12-16, 21-07 WD & WE	1.4	2.67
	Summer - 04-09	Peak	- 07-12 WD	4.5	6.78
		Off-Peak	- 12-07 WD & WE	1.0	1.51
10	Winter - 10-03	Peak	- 16-21 AD	3.8	8.10
		Off-Peak	- 21-16 AD	1.4	2.98
	Summer - 04-09	Peak	- 12-17 AD	2.7	5.75
		Off-Peak	- 17-12 AD	1.0	2.13
11	Winter - 10-03	Peak	- 16-21 WD	5.5	11.18
		Off-Peak	- 21-16 WD & WE	1.4	2.85
	Summer - 04-09	Peak	- 12-17 WD	3.9	7.93
		Off-Peak	- 17-12 WED &WE	1.0	2.03
12	Winter - 10-03	Peak	- 12-21 WD	2.6	5.33
		Off-Peak	- 21-12 WD & WE	2.0	4.10
	Summer - 04-09	Peak	- 07-16 WD	1.3	2.67
		Off-Peak	- 16-07 WD & WE	1.0	2.05

Rate	Seasons		Time-of-Day[a]	Relative Rates[b]	Absolute Prices (¢/kWh)[c]
13	Winter - 10-03	Peak	- 12-21 WD	5.5	9.11
		Off-Peak	- 21-12 WD & WE	1.4	2.32
	Summer - 04-09	Peak	- 07-16 WD	3.9	6.46
		Off-Peak	- 16-07 WD & WE	1.0	1.66
14	Winter - 12-03	Super Peak	- 07-12, 16-21 WD	7.8	7.0
		Peak	- 06-07, 12-16, 21-24 WD	5.4	4.84
		Off-Peak	- 24-06 WD & WE	2.0	1.79
	Spring/Fall	Super Peak	- 07-12, 16-21 WD	6.0	5.38
	-04-05, 09-11	Peak	- 06-07, 12-16, 21-24 WD	4.5	4.04
		Off-Peak	- 24-06 WD & WE	2.0	1.79
	Summer - 06-08	Super Peak	- 07-17 WD	6.0	5.38
		Peak	- 06-07, 17-24 WD	4.5	4.04
		Off-Peak	- 24-06 WD & WE	1.0	0.90
15	Winter - 12-03	Super Peak	- 17-21 WD	5.5	11 .44
		Peak	- 07-17,21-23 WD,07-23 WE	1.8	3.74
		Off-Peak	- 23-07 AD	1.4	2.91
	Fall - 09-11	Peak	- 07-23 AD	1.8	3.74
		Off-Peak	- 23-07 AD	1.4	2.91
	Summer - 04-08	Peak	- 07-23 AD	1.3	2.70
		Off-Peak	- 23-07 AD	1.0	2.08
16	Winter - 12-03	Super Peak	- 17-21 WD	8.4	11 .80
		Peak	- 07-17, 21-23 WD	3.8	5.34
		Off-Peak	- 23-07 WD & WE	1.4	1.97
	Fall - 09-11	Peak	- 07-23 WD	3.8	5.34
		Off-Peak	- 23-07 WD & WE	1.4	1.97
	Summer - 04-08	Peak	- 07-23 WD	2.7	3.79
		Off-Peak	- 23-07 WD & WE	1.0	1.40

a/ Times of day are described using a 24-hour clock.
WD = weekdays
WE = weekends
AD = all days
b/ All prices expressed relative to a summer off-peak price of 1.0.
c/ Absolute Prices (¢/kWh) for the year of 1983

3. Analytic Perspective

There are two effects which must be considered in measuring the impact of a new time-of-use rate structure on a household's load pattern. Naturally, if the price differential widens (even though electricity expenditure may be held constant), there is an incentive to move consumption from high-priced times of the week to low-priced times. This effect is referred to as the shifting effect. However, a further impact can come from the change in overall price of electricity. When households move from control to time-of-use rates the average price within a season may change for many reasons. There may be an overall movement in electricity prices relative to the consumer price index, a higher rate in the winter, a lower rate in the summer, or a movement in the price index due to a shifting of electricity from relatively more expensive peak to less expensive off-peak consumption. This latter effect is referred to as the conservation effect.

In examining the above effects, it is important to keep in mind that through the duration of the experiment there were many factors besides changing rate structures (some measurable and some not measurable) which can influence changing load shapes. In isolating the impact of a new rate structure, it is important that statistical models control for these other factors. They include such factors as changes in space heating and cooling equipment, water heating equipment, other major appliances, number of residents, weather and lifestyle.

The results discussed in this paper are based on econometric models which, while controlling for factors other than changing rate structure, isolated the effects of rates on load shapes. A log-linear demand equation for electricity estimated the conservation effect. The estimate of the shifting effect is a weighted estimate derived from two econometric demand systems, both describing how consumers efficiently allocate their electricity across time to meet their weekly electricity requirements. These two model structures are the Almost Ideal demand system (Deaton and Muellbauer (1980a)) and the Rotterdam (see Theil (1965) and Mountain (1988)) demand system. Through the experiment 16 "commodities" are used to describe the components of consumption in an average week of a month. These commodities are the aggregate kilowatt-hour consumption corresponding to periods with consecutive hours having the same price, the hours before and after Ontario Hydro's generation peak (the 7th hour and the 24th hour of a weekday) and time periods which are often times of municipality peaks (the 10 am-noon on weekdays and the 5 pm - 7 pm period on weekdays). Table 2 provides a listing of these kilowatt-hour aggregations for the monthly grouping. A brief discussion of these econometric models is provided in the Appendix.

Before using the inferences from these econometric models, it was important to assess the reliability of the models. A number of checks and diagnostics were performed. Behavioral and economic theory provide suggestions on variables of importance (such as appliance holdings, price structure and weather) as well as an explanatory framework consistent with maximization of consumer satisfaction. However, none of these theories or intuition can provide much information on appropriate functional forms. To select an appropriate set of elasticities of responsiveness, a strategy was developed which began by proposing a set of desirable features for the demand systems. Based upon the extent to which the models satisfied these features, a set of weights was proposed for integrating the impacts derived from the log-linear aggregate demand equation, the Almost Ideal model and the Rotterdam model. These desirable features can be subdivided into three categories.

The first of these components looked at how significantly the models captured the influence of variables which a priori were thought to influence demand patterns. Such variables include appliance holdings, electric heating, electric water heating and price structure. Whether the above variables were important was tested statistically using F-tests.

Regardless of whether the commodities under consideration are electricity or not, a second desirable feature is that the corresponding demand system-model should be consistent with the hypothesis of a household choosing electricity according to a timetable that minimizes the expenditure required to achieve a particular level of "electricity satisfaction." First, the demand systems should predict positive quantities or shares of electricity. Secondly, other things being equal, it is expected that as the price of electricity goes up during a particular time period, the households would reduce their consumption during that time period. An indicator of this reduction is the compensated peak elasticity which measures, for a given level of satisfaction, the percentage change in consumption during the peak period in response to a percentage increase in the price of electricity during the peak period. Given the above, it is expected that this compensated peak elasticity be negative. This is a requirement of concavity for the expenditure system. Concavity was tested for by looking at the compensated elasticities for the various rate groups along with their standard errors. A third desirable attribute for a demand system is the presence of symmetry. This is a technical feature which focuses on the second derivatives of the compensated demand curves. Although it is often considered to be a desirable condition, it is often not found in demand systems (see Deaton and Muellbauer (1980b, p.80)). Symmetry was tested for by a series of F-tests.

A third component, perhaps the most important, was the goodness of fit or predictability of the demand systems. The common yardstick across models was the commodity share. The focus was

Table 2: Aggregate Commodities

Weekend		Weekday	
1.	11pm - 7 am	7.	11pm - midnight
2.	7 am - noon	8.	midnight - 6 am
3.	noon - 4 pm	9.	6 am - 7 am
4.	4 pm - 5 pm	10.	7 am - 10 am
5.	5 pm - 9 pm	11.	10 am - noon
6.	9 pm - 11pm	12.	noon - 4 pm
		13.	4 pm - 5 pm
		14.	5 pm - 7 pm
		15.	7 pm - 9 pm
		16.	9 pm - 11pm

on four areas: the absolute deviation in the off-peak shares (also equal to the absolute deviation of the sum of the peak and super-peak shares), the 7 am - 11 pm weekday shares, the 10 am - noon weekday shares, and the 5 pm - 7 pm weekday shares. Both within- and out-of-sample prediction errors were computed.

The detailed findings of the above evaluations can be found in Mountain (1992) and they provided the basis for an overall integration of the results of these models.

The estimation of the log-linear equation permits the estimation of the overall aggregate demand elasticity for the experimental customers. The overall aggregate demand elasticity (ϕ) is the percentage change in aggregate electricity consumption due to a one percent change in the electricity price index. The estimation of the demand-systems permits the estimation of shifting through own- and cross- price compensated elasticities. These compensated elasticities are conditional on aggregate electricity expenditure. The compensated price elasticity for electricity in time period i in response to a price change in time period j is τ^C_{ij}. Furthermore, from the demand system, expenditure elasticities by time-of-day (η_i) can be calculated (η_i denotes the percentage change in consumption in time period i in response to a one percent change in electricitiy expenditure).

In calculating the percentage impacts on consumption in various time periods through the week, it is necesary to make use of the compensated elasticities, the expenditure elasticities, the overall aggregate demand elasticity and the shares of expenditures in particular time periods ($W_i=P_iq_i/\Sigma P_iq_i$, where P_i and q_i are the prices and quantities of electricity consumed in time period i). For example, the percentage impact in consumption in aggregate time period i is [exp ($\Delta \ln q_i$)-1]*100, where

$$\Delta lnq_i = \sum_{j=1}^{3} \tau^F_{ij} \ln(P_{jT}/P_{j,T-1}), \qquad (1)$$

$$where\ \tau^F_{ij} = \tau^C_{ij} + \eta_i \phi W_j$$

and where i,j = 1,2,3 represent the super-peak, peak and off-peak periods. P_{jT} represents the price of electricity for commodity j under time-of-use rates and $P_{j,T-1}$ is the price of electricity for commodity j before time-of-use rates. The following impacts are really a simulation of participants' consumption patterns if all other factors (including weather, appliances and tastes) had remained as recorded in the control year.

4. Results

4.1 Elasticities

Before discussing the impacts on load shape it is worthwhile to examine the estimated compensated elasticities and aggregate demand elasticities. These are the key ingredients for estimating the time-of-use effects and for simulating the impact of other residential time-of-use rate structures. Table 3 summarizes the compensated (τ^C_{ij}) price elasticities for an all-electric household. (Note that since $\sum_{j=1}^{3} \tau^C_{ij} = 0$, for brevity not all elasticities are calculated.)

A brief look at Table 3 provides a few interesting observations. Generally, winter elasticites are much larger than the summer elasticities. The off-peak elasticities are fairly large. The super-peak own-elasticities (see rate cells 14 and 16) tend to be lower than the peak own-elasticities.

The all-electric elasticities tend to be larger (although not significantly) than other household types. (See Mountain (1992) for more detail.) The average winter (October-March) aggregate demand elasticity (ϕ) is -.12 and the average summer (April-September) aggregate demand elasticity is -.09.

Table 3: Summary of Compensated Price Elasticities – All-Electric

Rate Cell	SP:SP[1]	SP:P	P:SP	P:P	OP:P	OP:OP
			January			
4				-.044		-.067
5				-.040		-.070
7				-.040		-.070
9				-.024		-.024
11				-.025		-.010
13				-.082		-.057
14	-.027	.004	.006	-.055	.037	-.058
16	-.024	-.004	-.001	-.039	.057	-.082
			July			
Rate Cell	SP:SP[1]	SP:P	P:SP	P:P	OP:P	OP:OP
4				-.025		-.040
5				-.017		-.035
7				-.017		-.035
9				-.038		-.014
11				-.120		-.050
13				-.050		-.037
14	-.043	.034	.057	-.055	-.002	-.013
16				-.025		-.044

P = peak
OP = off-peak
SP = super-peak

1/ x:y indicates the percentage change in x in response to a 1% change in the price of y.

It is difficult to make an exact comparison of these results with those of other studies because of differences in length of rate periods and relative prices. Furthermore, the methodologies are not directly comparable. Comparisons will be made for rate structures like rate cell 5 (16-hour peak with 3.9:1 peak: off-peak price differential) and like rate cell 13 (9-hour peak with 3.9:1 peak: off-peak price differential). In addition, comparisons will be made regarding aggregate demand elasticities and winter-summer differences in responsiveness.

Using a study by Caves, Christensen and Herriges (1984) (which was based on data from Carolina Power and Light, Connecticut Light and Power, Los Angeles Department of Water and Power, Southern California Edison and Wisconsin Public Service), all-electric peak elasticities are estimated to be -.038 for both the winter and the summer. This is about the same estimate as this study's January estimate and about twice that of this study's July estimate. Among their findings are: adding appliances increases elasticities of substitution; adding air-conditioning increases the elasticity of substitution; adding electric heating increases the substitution between weekdays and weekends. The Ontario Hydro study finds some but not significant differences in elasticities of substitution between all-electric versus non-electric households. The study does not find a significant elasticity difference between water heating and non-water heating households.

Kohler and Mitchell (1984) find, for a rate treatment like rate cell 13 in Wisconsin, a peak elasticity of -.048 (-.057 for rural) in the summer and -.038 (-.074 for rural) in the winter for urban households. This would compare with rate cell 13 with peak elasticities of -.050 in July and -.082 in January. Ontario Hydro tends to show the same responsiveness as urban Wisconsin in the summer but higher responsiveness in the winter. Ontario Hydro's winter results tend to be similar to that of the 9 to 12 hour peak elasticity for Wisconsin of between -.03 and -.04.

From the above, it seems that the Ontario Hydro's elasticities relative to those of other studies are higher in the winter and lower in the summer. There is also evidence of this relationship in Caves and Christensen (1980) and Caves, Christensen and Herriges (1987). Another observation is that like Caves and Christensen (1980) and Atkinson (1981), peak elasticities tend to be larger for peak periods of smaller duration.

Most studies have not really come to grips with the estimation of the aggregate demand elasticity. Many of the studies assume (e.g., Caves and Christensen (1980) and Kohler and Mitchell (1984)) an aggregate demand elasticity of either -.1 or -.2. The Caves Christensen and Herriges (1984) paper tried to estimate the aggregate demand elasticity but found it to be near zero. However, they do not believe these numbers and attribute this to the "relatively minor variation observed within experiments in the ratio of electricity prices to other goods' prices." (p.197). As mentioned, the Ontario Hydro study estimates winter and summer aggregate elasticities of -.12 and -.09, respectively.

4.2 Summary Percentage Changes in Load Impacts

The aggregate monthly percentage and kW impacts are presented in Table 4a for all-electric households and non-electric households for the months of January and July. These are calculated using equation (1). The kilowatt impacts are calibrated to Ontario 1989 levels. The peak reductions are naturally higher where the price ratio is highest and the largest reduction occurs with a medium-length time-period. (e.g., For rate cell 13 a 12.54% reduction occurs in January.) For the treatments with 16-hour peaks, the reductions for an all-electric household range from 5.55% for rate cell 4 to 6.87% for rate cell 5. Rate cell 16 is very effective in reducing super-peak consumption (e.g., from 5 pm to 9 pm on weekdays). The off-peak increases are largest in January for rate cell 7. Overall, the change in total consumption ranges from a reduction of 0.54% (for rate cell 16) to an increase of 3.01% (for rate cell 7).

The load impacts in July for an all-electric household show a large variation in size. The impacts for the peak period range from a reduction of 12.81% for rate cell 11 up to a 2.15% increase for rate cell 5. There are significant increases in total consumption for the summer (up to 5.94% increase for rate cell 9). The peak reduction in rate cell 11 is very large in July; however, the reduction applies to a very short peak period. It is evident from the July figures that the cheaper summer prices cause increases in consumption - offsetting the reductions in peak caused by time-of-day differentials. The extent of this cheapness is displayed in Table 5. With the exception of rate cell 7 (a non-seasonal rate structure) price reductions range from 18.6% (rate cell 14) to 39.67% (rate cell 9).

Table 4b also reports similar load impacts for a non-electric household. There generally is little difference between percentage response by an all-electric (Table 4a) versus non-electric household. Of course, as one moves from a non-electric to an all-electric household, the kilowatt reductions can move from .15 to .63 kW (for rate cell 13). Perhaps one might venture to say that in the summer there is slightly more substitution by those with air-conditioning.

The 10am - noon weekday time period and 5 pm - 7 pm weekday time period are often the times that local municipal utilities attain their peak

Table 4a: Impacts on Consumption by Aggregate Time Periods – All-Electric Households

Rate Cell	Change in Super-Peak Demand %	kW	Change in Peak Demand %	kW	Change in Off-Peak Demand %	kW	Change in Total Demand %	kW
January								
4			-5.55	-.29	5.58	.27	0.02	.00
5			-6.87	-.36	7.28	.35	0.12	.01
7			-4.27	-.22	10.49	.50	3.01	.15
9			-4.75	-.26	1.89	.09	-0.25	-.01
11			-5.24	-.28	0.58	.03	-0.35	-.02
13			-12.54	-.63	7.77	.39	2.12	.11
14	-3.40	-.19	-3.47	-.17	6.38	.30	0.86	.04
16	-8.16	-.44	-6.58	-.34	6.02	.29	-0.54	-.03
July								
4			-0.59	-.02	7.56	.17	2.64	.07
5			2.15	.06	9.41	.21	5.57	.14
7			-2.09	-.06	4.72	.11	1.09	.03
9			-0.91	-.02	7.00	.18	5.94	.15
11			-12.81	-.39	8.41	.20	4.98	.13
13			-4.21	-.11	7.46	.18	4.45	.11
14	0.22	.01	3.41	.10	3.12	.07	2.29	.06
16	0.47	.01	7.50	.17	3.78	.10		

demands. Load impacts at these critical hours of the week in January are shown in Table 6. It is apparent that it is very easy to get people to move out of the 10 am - noon weekday time period; however, significant super-peak to off-peak price ratios are necessary (e.g., 6:1 for rate cell 16) to get households to reduce significantly their consumption in the 5 pm - 7 pm weekday time period. Another observation is that rate treatments with very concentrated and narrow peaks (e.g., 11, 14 and 16) are more likely to cause significant reductions in the 5 pm - 7 pm weekday period.

What about the time of Ontario's generation peak or the 7 am - 11 pm weekday time period? Table 7 shows the impacts for the 16-hour peak period, regardless of whether this was the peak pricing period. Rate cells 5 and 16 are the most effective in January. Rate cell 7 (where there is no seasonality) shows the highest reduction in July. The highest increase in the 16-hour peak period for July occurs

Table 4b: Impacts on Consumption by Aggregate Time Periods – Non-Electric Households

	January							
Rate Cell	Change in Super-Peak Demand		Change in Peak Demand		Change in Off-Peak Demand		Change in Total Demand	
	%	kW	%	kW	%	kW	%	kW
4			-5.65	-.07	5.23	.05	-0.60	-.01
5			-6.92	-.08	6.29	.06	-0.79	-.01
7			-4.49	-.05	9.66	.10	2.07	.02
9			-4.78	-.06	1.86	.02	-0.44	-.00
11			-5.93	-.09	0.77	.01	-0.57	-.01
13			-12.06	-.15	7.83	.08	1.47	.02
14	-3.47	-.04	-4.67	-.05	5.21	.05	-0.18	-.00
16	-8.29	-.12	-6.51	-.07	5.14	.05	-1.39	-.02
	July							
Rate Cell	Change in Super-Peak Demand		Change in Peak Demand		Change in Off-Peak Demand		Change in Total Demand	
	%	kW	%	kW	%	kW	%	kW
4			-0.46	-.00	6.42	.05	2.86	.03
5			2.33	.02	9.66	.08	5.87	.05
7			-1.98	-.02	4.79	.04	1.27	.01
9			0.15	.00	7.08	.06	6.15	.05
11			-12.30	-.12	8.06	.07	5.00	.04
13			-3.45	-.03	7.30	.06	4.54	.04
14	0.51	.00	3.26	.03	3.40	.03	2.42	.02
16			1.23	.01	6.90	.06	3.99	.04

Table 5: Overall Percentage Change in Electricity Price Index – All-Electric

Cell	January	July
4	9.41	-19.23
5	16.77	-38.80
7	-1.34	3.61
9	50.60	-39.67
11	12.18	-19.41
13	7.81	-21.02
14	9.59	-18.61
16	17.54	-29.57

with rate cell 5. If a rate cell is desired for its reduction in the 7 am - 11 pm on weekdays on average for the whole year, rate cells 4 and 11 to 16 fulfil this requirement.

Table 6: Impacts on Consumption at Critical Hours – All-Electric Households (January)

Rate Cell	Change at 10 am - noon (weekday)		Changes at 5 pm - 7 pm (weekday)	
	%	kW	%	kW
4	-12.00	-.64	-1.55	-.08
5	-14.97	-.80	-2.65	-.14
7	-12.61	-.67	0.01	.00
9	-15.81	-.84	-0.31	-.02
11	-2.95	-.16	-5.05	-.27
13	-11.79	-.63	-3.60	-.19
14	-7.21	-.39	-4.78	-.26
16	-11.20	-.60	-8.39	-.45

Table 7: Impacts on 16-Hour Generation Peak – All-Electric Households, 7 am - 11pm Weekdays (% Change)

Rate Cell	January	July
4	-5.16	1.08
5	-6.58	4.64
7	-3.82	-1.05
9	-4.89	5.50
11	-3.95	0.91
13	-5.53	1.96
14	-5.10	1.48
16	-6.71	2.74

4.3 System Impacts

Although the above kilowatt impacts (in Tables 4a and b, 6 and 7) may not be perceived as very large numbers, one can take these impacts and simulate what would occur in the Ontario Hydro system if every household were placed on time-of-use rates. This set of simulations uses 1990 household saturation rates from the 1990 Residential Appliance Survey. The megawatt changes in peak, off-peak and total consumption are in Table 8. In January, the megawatt peak reductions range from 204.6 for rate cell 14 to 703.1 for rate cell 13. During the super-peak time, rate cell 16 causes a reduction of about 525 megawatts. To put these numbers into perspective, an Ontario Hydro nuclear generating unit located at Pickering is about 515 megawatts and these units located at Darlington average about 900 megawatts. In 1992, with an approximate present value of $1000 per kW, the cost savings for, say, 200 MW would

Table 8: Average Megawatt Loads and Impacts for Residential Customers in the Ontario Hydro System*

Rate Cell	Super-Peak		Peak		Off-Peak		Total	
January								
	Pre-TOU	Change	Pre-TOU	Change	Pre-TOU	Change	Pre-TOU	Change
4			5683.4	-318.9	4881.5	264.5	5243.6	-16.4
5			5683.4	-393.1	4881.5	333.2	5243.6	-15.8
7			5683.4	-250.3	4881.5	494.0	5243.6	132.3
9			5925.4	-284.2	4975.5	94.4	5243.6	-18.5
11			6249.2	-350.1	5078.4	30.9	5243.6	-12.8
13			5722.1	-703.1	5080.7	391.4	5243.6	90.4
14	5925.4	-204.6	5177.9	-213.6	4882.6	285.1	5243.6	17.0
16	6338.7	-524.6	5464.9	-354.8	4881.5	276.0	5243.6	-38.9
July								
	Super-Peak		Peak		Off-Peak		Total	
	Pre-TOU	Change	Pre-TOU	Change	Pre-TOU	Change	Pre-TOU	Change
4			4561.8	-26.6	3695.5	269.9	4068.1	118.6
5			4561.8	98.6	3695.5	356.3	4068.1	234.1
7			4561.8	-95.2	3695.5	178.8	4068.1	49.3
9			3728.8	-17.9	4120.8	275.4	4068.1	246.2
11			4688.0	-629.9	3971.9	325.6	4068.1	201.3
13			4104.5	-163.2	4056.5	299.8	4068.1	184.3
14	4208.4	14.2	4736.3	156.3	3716.6	117.5	4068.1	92.8
16			4561.8	37.3	3695.5	265.4	4068.1	158.5

* Pre-TOU loads and changes are adjusted to 1989 consumption levels.

be $200 million. Except for rate cells 7, 13 and 14, there are generally overall reductions in total consumption. In the summer the experimental time-of-use rate structures caused increases in total consumption for all rate cells. Nevertheless, for most of the rate cells there were peak reductions - albeit small.

5. Concluding Comments

The first and most important comment is that time-of-use rates do make a difference in residential load shapes. In January, rate structures with 16-hour peaks will cause a reduction in the peak of about 5.6% for a price ratio of 2.6:1 and a reduction of 6.9% for a price ratio of 3.9:1. In July, the changes in the peak period range from a reduction of .6% to an increase of 2.2%. Nevertheless, a great deal of this lack of peak reduction in the summer is due to the large drop in overall price of electricity (e.g., 19.23% for rate cell 4 and 38.80% for rate cell 5). Over the whole winter season, the peak reductions are at about 2% less than those in January. Similarly, July peak reductions seem to be greater than those in the rest of the summer.

Rate cells with a 9-hour peak do better in reducing their respective peaks, but do not do as well in the broader 16-hour peak period. Rate cells with very short peak periods are generally not that effective in solving broader peak problems, but can be effective with respect to evening peaks if a reasonably large peak:off-peak price differential is used. Three-part rates can be very effective in getting super-peak period reductions if implemented with a fairly large super-peak:peak and super-peak: off-peak price ratio (i.e., like rate cell 16 with price ratios of 8.4:3 and 8.4:1.4, respectively).

Relative to other jurisdictions, this Ontario study shows higher elasticities in the winter and the same or perhaps lower elasticities in the summer. Substitution elasticities do not seem to be a function of the presence of water heating. Elasticities tend to be slightly larger (not significantly) for all-electric households.

With respect to the broad 16-hour (7 am - 11 pm) period, the most effective rate treatment for moving electricity out of this period is a rate treatment with the peaks defined to be the 16-hour period (eg. rate cell 5 with a peak:off-peak period ratio of 3.9:1) or a rate treatment (like rate cell 16) with a super-peak period in the middle. The reduction in January for rate cells 5 and 16 are 6.58% and 6.71%, respectively. Some municipalities have a morning peak (e.g., 10 am - noon) and some have an evening peak (e.g., 5 pm - 7 pm). It is relatively easy to get households to move out of the 10 am - noon time period. It is not so easy to get households to move out of the 5 pm to 7 pm period. A rate cell with a peak focused on this time period (or hours around it), with a high peak:off-peak (e.g., like rate cell 11) or a high super-peak:peak (e.g., like rate cell 16) price ratio, is necessary to cause a movement out of the evening peak.

The concern about needle-peaking in boundary hours for the residential sector is not an issue. Generally, increases were not sufficient to cause a new peak during the day.

With respect to analysis of residential time-of-use rate impacts and this experiment's results, where should researchers go from here?

The above elasticities and impacts must be viewed as intermediate-run. They are certainly not short-run since participants were subject to these rates for up to five years in length. They are not long-run since participants did not have long enough to consider it worthwhile for making large capital investments on new heating, cooling, water heating or time-automated appliance systems. More thought must be given to how much larger these impacts would be in the long run - particularly where fuel switching is an option or may be encouraged. For example, higher winter rates in the long run must surely move households away from electric heating.

In this paper, one residential system-wide scenario was forecast for the province. How would this scenario change if time-of-use rates were voluntary and space and water heating fuels were allowed to change? Adaptation of the existing elasticities and impact-estimation models would facilitate this.

How would the system-wide scenario change if the peak:off-peak ratio were much wider than that in the experiment? The overall elasticities computed with the above models will be of great value in such extrapolations; however, more knowledge on what is really fixed and committed versus discretionary and substitutable would be helpful. Indeed, it would be helpful to have a framework which can identify particular committed versus flexible electricity loads in a conditional demand context.

This study used aggregate demand elasticities of between -.09 and -.12. This was a distinctive feature of the above results. Many other experiments did not recover a reliable aggregate demand elasticity. Nevertheless, further exploration and verification of what was found in this study is required.

In summary, while some of the results from the Ontario Hydro residential experiment are similar to other jurisdictions and while some are distinctive, it is safe to say that these results have and will be of overwhelming value in analysis of residential load profiles under a variety of time-of-use rate structures and alternative demographic/equipment profiles.

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Appendix: Model Description

The purpose of this appendix is to provide a brief description of the underlying econometric models.
The model which describes aggregate demand is

$$\ln(qT_{mny}) = \sum_{y=1}^{Y} \alpha_{ny} D_y + \sum_{k=1}^{K} \theta_{kn} A_{kmny} + \phi_n \ln(P_{mny}) + \sum_{j=1}^{J} \lambda_{jn} Inc_{jy}$$

where qT_{mny} is the aggregate amount of electricity consumed in month n of year y by household m,
D_y is a dummy variable indicating the year of the observation
P_{mny} is a real price index of qT_{mny}
and Inc_{jy} is an income category for category j (measured in real dollars)
The coefficient ϕ_n is referred to as the aggregate demand elasticity.

Both the Almost Ideal demand Model (A-Model) and the Rotterdam Model (R-Model) describe a system of demand equations for electricity consumption by time period during the week. The demand systems can be viewed as being derived from a household m allocating its consumption of electricity across the week for the purpose of minimizing its electricity expenditure to achieve a particular level of satisfaction. The degree to which a household can allocate or shift electricity is a function of its heating type, the weather, its appliance-mix and the number of household members.

This optimal (minimum) electricity expenditure (C*) for an average week in a particular month can be written as $\ln C^*_m = g(\ln P_{1m}, \ln P_{2m}, \ldots, \ln P_{Im}, U, A_{1m}, \ldots, A_{Km}, T)$ where $\ln P_{im}$ denotes the logarithm of electricity prices for time i, U denotes the level of electricity satisfaction, A_{kmt} denotes the appliance type k and T is an indicator of tastes. The corresponding optimal expenditure shares ($W_{im} = P_{im} q_{im} / \Sigma P_{im} q_{im}$ where q_{im} is the quantity of electricity consumed in time period i) are
$W_{im} = f_i(\ln P_{1m}, \ln P_{2m}, \ldots, \ln P_{Im}, \ln C^*_m, A_{1im}, \ldots, A_{Kim}, T)$.

The A-model comes from a second order approximation of ln C*. Nevertheless, the residential specification of the demand shares are essentially first order approximations.

$$W_{im} = \alpha_i' + \sum_{j=1}^{I-1} \gamma_{ij} \ln(P_{jm}/P_{nm}) + \beta_i[\ln(C^*_m/P_{nm}) - \ln(P_m/P_{nm})] \quad for\ j = 1,2,\ldots,I$$

$$where \quad \ln(P_m/P_{nm}) = \sum_{i=1}^{I-1} \alpha_i' \ln(P_{im}/P_{nm}) + \frac{1}{2} \sum_{i=1}^{n-1} \sum_{j=1}^{n-1} \gamma_{ij} \ln(P_{im}/P_{nm}) \ln(P_{jm}/P_{nm})$$

$$and \quad \alpha_i' = \alpha_i + \Theta_{iT} + \sum_{k=1}^{K} \mu_{ki} A_{kim}$$

A noteworthy feature of this system is its non-homotheticity. The implication of this is that as a household spends more money on electricity, it does not necessarily spend the increase proportionally through the day. This is a feature which generally has not been integrated into models of electricity demand (with the exception of Atkinson (1981)). The R-model can be derived from a first order approximation of the share function (f_i). However, the final specification is not in levels but in first differences (shown as Δ). The specification is

$$\overline{W}_{im}\Delta\, lnq_{im} = a_i + \sum_{k=1}^{K} a_{ik}\Delta A_{kim} + \sum_{j=1}^{I-1} b_{ij}\Delta ln(P_{jm}/P_{Im}) + b_i(\sum_{j=1}^{I}\overline{W}_{jm}\Delta lnq_{jm}),$$

where $\overline{W}_{im}$ are average expenditure shares over two relevant time periods. The R-system also possesses the non-homothetic feature.

For the two models a monthly grouping is performed. Here there is an assumed commonality of preference-structures across all rate groups, but preferences are specific to a month. All households' data are used in a monthly regression. For example, for the month of January, we would use all households' data for the month of January in the control year and the time-of-use years. Sixteen commodities, as described in Table 2 of the text, are used to describe the components of consumption in an average week of a month.