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Residential winter kW h responsiveness under optional time-varying pricing in British Columbia

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HIGHLIGHTS

- Estimated residential kW h responsiveness under winter time-varying pricing in BC.
- Found statistically significant estimates of elasticity-of-substitution.
- Time-varying pricing sans load control causes a peak kW h reduction of 2.6–9.2%.
- Load control raises these reduction estimates to 9.2% and 30.7%.

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ABSTRACT

A large sample of daily electricity consumption and pricing data are available from a pilot study conducted by BC Hydro in British Columbia (Canada) of its residential customers under optional time-varying pricing and remotely-activated load-control devices for the four winter months of November 2007–February 2008. We use those data to estimate the elasticity of substitution σ, defined as the negative of the percentage change in the peak-to-off-peak kW h ratio due to a 1% change in the peak-to-off-peak price ratio. Our estimates of σ characterize residential price responsiveness with and without load control during cold-weather months. While the estimates of σ *sans* load control are highly statistically significant ($\alpha = 0.01$), they are less than 0.07. With load control in place, however, these σ estimates more than triple. Finally, we show that time-varying pricing *sans* load control causes a peak kW h reduction of 2.6% at the 2:1 peak-to-off-peak price ratio to 9.2% at the 12:1 peak-to-off-peak price ratio. Load control raises these reduction estimates to 9.2% and 30.7%.

1. Introduction

Three transformative events have taken place in the electricity industry. The first event is restructuring designed to introduce wholesale-market competition in Australia, New Zealand, parts of North and South America, and Europe [1,2]. The second event is the large-scale development of wind generation, thanks to (a) advances in our ability to economically harvest the inexhaustible, if somewhat erratic, wind that nature bestows upon us [3,4], and (b) support from government policies to do so [5,6]. The third event is the development of smart grids that enhance (a) market competition and liquidity, (b) system asset utilization, flexibility, intelligence, resilience and reliability, and (c) the integration of renewable energy resources into the electricity grid [7–9].

Insofar as wholesale-market competition is concerned, an empirical fact is that electricity spot-market prices are inherently volatile, with occasional sharp spikes, thanks to: daily fuel-cost variations, especially for the natural gas now widely used in combined-cycle gas turbines and combustion turbines; weather-dependent seasonal demands with intra-day and inter-day fluctuations that must be met in real time by generation and transmission already in place; limited economic viability of energy storage systems; changes in available capacity caused by planned and forced outages of electrical facilities; precipitation and river flow for a system with significant hydro resources; carbon-price fluctuations that affect the thermal generation that uses fossil fuels; transmission constraints that cause transmission congestion and generation redispatch; and lumpy capacity additions that can only occur with long lead times [10–13].

The electricity price volatility and its accompanying spikes are in turn exacerbated by the second event of large-scale development of wind generation [14]. Since wind generation has zero fuel

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cost, it is economically dispatched to displace high-fuel-cost marginal generation [15,16], unless curtailed to resolve grid congestion and instability [17,18]. Wind-generation output, however, is random and intermittent, thus presenting integration challenges that can be mitigated by a smart grid armed with demand response (DR) resources [19–25].

Related to the third event of smart-grid development is the advanced metering infrastructure that allows a load-serving entity to implement time-varying electricity pricing to convey spot-price signals for effective DR management of system peaks, and economic efficiency [26–37]. That entity can be a local distribution company such as PG&E and SCE in California (U.S.) or an integrated utility such as BC Hydro in British Columbia (Canada). Reinforcing this view is the empirical evidence of statistically-significant peak kW reductions by households in response to time-of-use (TOU) pricing and critical-peak pricing (CPP) [38–43]. For example, TOU pricing is estimated to reduce residential winter evening peak kW by 5–10% in the Pacific Northwest area of the U.S. [44,45] and 10–15% in New Zealand [46]. The winter estimates for CPP are about 4–6% for residents in Washington, DC [47].

Most evidence to date, however, comes from summer-peaking utilities with relatively high electric rates. As reported in a 2010 survey of 15 experiments [42], TOU pricing induces (a) summer afternoon peak kW reductions of 3–6%, and (b) summer peak kW reductions of 13–20% due to CPP alone, and 36–44% when assisted by an enabling technology such as smart thermostats.

Partially filling this gap in empirical evidence is a recent paper [48] on the winter evening peak kW response of participants in BC Hydro's residential TOU/CPP pilot study in British Columbia, a winter-peaking Canadian province with low electric rates compared to other regions of North America.[1] Based on a large sample of hourly data for 1717 customers on 83 working weekdays from November 2007 through February 2008, the parameter estimates of 24 hourly kW regressions show that optional TOU pricing can reduce the evening peak kW by 4–11% [48]. Moreover, the incremental impact of CPP (beyond the TOU effect) is a 9–12% reduction in the peak kW. When aided by remotely-activated load control of space and water heating, CPP can achieve in excess of a 35% total reduction in the peak kW.

While transparent and informative, the analysis in [48] does not provide price elasticity estimates for predicting customer demand behavior under TOU/CPP designs that were not considered in the pilot study. The present paper fills in this gap by using daily kW h data from the pilot study, by TOU period, to estimate the residential responsiveness to optional time-varying pricing. We focus on kW h responsiveness by TOU period because the lack of hourly price variations precludes our estimation of a system of 24 hourly demand equations, as done in [49,50].

Based on three alternative estimation methods, our estimates answer the following questions that are the focus of our research:

- What are the estimates of the elasticity of substitution (σ = negative of the percentage change in the peak-to-off-peak kW h ratio due to a 1% change in the peak-to-off-peak price ratio), for BC Hydro's residential customers, under voluntary time-varying pricing? We find statistically-significant estimates ($\alpha = 0.01$) of 0.054–0.069,[2] which are at the low end of the ranges reported in [38–40,42].
- How does remotely-activated load control affect the estimates of σ? We find that load control increase the σ estimates by 0.15–0.18. To the best of our knowledge, this is the first evidence on the effect of a DR-enabling technology on a customer's winter σ estimates.
- What is the peak kW h reduction due to time-varying pricing? Without load control, the estimated reduction is about 2.6% at the low-end 2:1 peak-to-off-peak price ratio, which rises at a decreasing rate to about 9.3% at the high-end 12:1 price ratio. With load control, the estimated reduction is 9.2% at the 2:1 price ratio and 30.7% at the 12:1 price ratio. While corroborating the mostly summer evidence reported in a 2012 survey [43], these estimated reductions sharply confirm the effect of a DR-enabling technology on a customer's winter peak kW h responsiveness under optional time-varying pricing.

The paper proceeds as follows. Section 2 describes the pilot study, thus defining the scope of our regression analysis. Section 3 presents our empirical approach. Section 4 reports the results, and Section 5 concludes.

2. BC Hydro's TOU/CPP pilot study

The daily kW h data by TOU on 83 working weekdays in November 2007–February 2008 are derived from 1717 single-family homes in three areas of British Columbia (Canada): the Lower Mainland region (major city: Vancouver); the city of Fort St. John in the Northern Interior; and the city of Campbell River on Vancouver Island. These customers participated in the second year of BC Hydro's pilot study that entailed one flat rate schedule (RS) 1101 and eight TOU rate schedules.[3] Shown in Fig. 1, each TOU tariff's peak hours can be: (1) 4–9 pm; (2) 4–8 pm; or (3) 8–11 am and 4–8 pm. The evening peak hours aim to cover BC Hydro's system peak hour of 5–6 pm on a cold winter weekday. The morning peak hours aim to cover the local peak hour of 9–10 am on a cold winter weekday on Vancouver Island.

The TOU rate schedules have high peak and off-peak rates when compared to the non-TOU flat rate. For example, RS1142 and RS1143 have peak rates that far exceed their off-peak rate of 6.15 ¢/kW h, which is only slightly lower than the flat rate of 6.33 ¢/kW h. To encourage customer participation, the pilot study offered each TOU customer an upfront payment equal to the estimated bill increase from the TOU rates. Each TOU customer's payment was the difference between (a) the customer's pre-pilot weather-adjusted peak and off-peak kW h estimates at TOU rates, and (b) the customer's pre-pilot weather-adjusted kW h consumption at the non-TOU flat rate.[4]

RS1141B and RS1144A contain a CPP rate of 50 ¢/kW h, which is triggered with advanced notice by 5 pm the day before a CPP event. The complete list of CPP event days is: 11 December 2007 (Tuesday), 18 December 2007 (Tuesday), 09 January 2008 (Wednesday), 18 Jan-

[1] While 90% of BC Hydro's electricity generation comes from energy-limited hydro resources, peak-demand reduction has a capacity value of approximately C$150/kW-year in BC Hydro's consideration of (a) retiring the aging 900-MW Burrard Thermal Generation Station in Vancouver, and (b) procurement of new supplies to meet its system-peak growth.

[2] A σ estimate is said to be statistically significant at $\alpha = 0.01$ when its p-value is below 0.01, thereby rejecting the null hypothesis of $\sigma = 0$ based on a two-tail t-test.

[3] Based on single-family residents identified from its billing data file, BC Hydro recruited 2070 participants via direct mail in early 2006, 699 of whom were allocated to the control group and the rest to the treatment group. The allocation was balanced, without systematic differences in customer attributes between the two groups. After the pilot's first winter of November 2006–February 2007, the participants were asked to re-enroll, contributing to 1632 of the 1717 participants shown in Fig. 2. The remaining 85 participants were newly recruited to permit estimation of the peak-load effect of shortening the 4–9 pm peak period by 1 h, to 4–8 pm.

[4] While the participation payment was made before the customer's actual consumption under time-varying pricing, it could shrink the σ estimates for two reasons. First, the payment might have encouraged customers with poor load-shifting capability to join the pilot study. Second, it might have exacerbated the free-rider problem in which residents with relatively low peak consumption could enjoy TOU/CPP bill savings without changing their demand behaviors [26,27,31,52]. Notwithstanding these caveats, our σ estimates demonstrate statistically-significant ($\alpha = 0.01$) effectiveness of optional time-varying pricing in reducing residential peak kW h.