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Winter Residential Optional Dynamic Pricing: British Columbia, Canada

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ABSTRACT

This paper estimates the daily kWh responses on a working weekday of 1326 single-family-home residents who voluntarily participated in a residential optional dynamic pricing (RODP) pilot in the winter-peaking coastal province of British Columbia (BC) in western Canada. Based on the pilot's operation in November 2007–February 2008, we estimate that the kWh reduction in the peak period of 4–9 pm on a working weekday *sans* an in-home display (IHD) is: (a) 2.2% to 4.4% at time-of-use tariffs with peak-to-off-peak price ratios of 2.0 to 6.0; and (b) 4.8 to 5.3% at critical peak pricing tariffs with peak-to-off-peak price ratios of 8.0 to 12.0. The IHD approximately doubles these estimated peak kWh reductions. As BC residents already have smart meters with an IHD function, these findings recommend exploring the use of a system-wide RODP program to improve the BC grid's system efficiency.

Keywords: Residential optional dynamic pricing, Electricity demand by time-of-use, In-home display, British Columbia

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1. INTRODUCTION

Using time-of-use (TOU) and critical peak pricing (CPP) tariffs, residential optional dynamic pricing (RODP) improves an electric grid's system efficiency by shifting a participant's kWh consumption from peak hours of high marginal costs to off-peak hours of low marginal costs (Joskow and Wolfram, 2012).[1]

By providing real-time information feedback, an in-home display (IHD) magnifies a customer's kWh responses to RODP (Faruqui and Sergici, 2010; Gans et al., 2013; Jessoe and Rapson, 2014). Relative to a nonlinear tariff with non-TOU rates (Ito, 2014), an IHD-aided RODP program improves how an electric utility may price its service for residential customers (Woo et al., 2008, 2014), who can in turn make informed decisions to achieve conservation by reducing their total kWh consumption (Darby, 2006; Faruqui et al., 2010; Delmas et al., 2013; Houde et al., 2013; Jessoe and Rapson, 2014).

1. The extensive evidence on the estimated kWh responses to RODP is well documented by several surveys (DOE, 2006; Faruqui and Sergici, 2010; Newsham and Bowker, 2010; Faruqui and Palmer, 2012), obviating the need for a similar literature review in this paper.

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This paper addresses the interesting and important policy of RODP when residents are equipped with IHDs to monitor their electricity usage. To do so, it presents a Generalized Leontief (GL) demand analysis of kWh consumption by TOU based on 1326 opt-in participants of a RODP pilot in the winter-peaking coastal province of British Columbia (BC) in western Canada. Our sample is a panel of non-missing customer-day observations of peak and off-peak kWh consumption observed over 83 working weekdays in November 2007–February 2008.

Our key findings are as follows:

- RODP *sans* an IHD is estimated to reduce a participant's daily winter peak kWh by 2.2% to 4.4% at TOU peak-to-off-peak price ratios ("price ratio" hereafter) of 2.0 to 6.0 and 4.8% to 5.3% at CPP price ratios of 8.0 to 12.0. These estimated peak kWh reduction are less than the 10% estimate for New Zealand at a price ratio of 3.5 (Thorsnes et al., 2012) and the 4.5% to 8.7% estimates for Ireland at price ratios of 1.7 to 4.3 (Di Cosmo et al., 2014; Carroll et al., 2014).[2]
- The IHD approximately doubles the peak kWh reduction estimates, corroborating the empirical evidence reported by Faruqui and Sergici (2010), Faruqui and Palmer (2012), Gans et al. (2013), Carroll et al. (2014), and Jessoe and Rapson (2014).
- The IHD is estimated to reduce a participant's daily total kWh consumption by 2.4% to 3.5% for TOU price ratios of 2.0 to 6.0, affirming information feedback's conservation effect (Darby, 2006; Faruqui et al., 2010; Delmas et al., 2013; Martin and Rivers, 2015).
- At the pilot's CPP price ratio of 8.0, an IHD-aided system-wide RODP program is projected to reduce BC's peak demand by 11.5 MW to 34.6 MW, depending on the assumption used to characterize the program's participation rate. Associated with this peak demand reduction is an estimated capacity cost saving of C$24.4 million to C$73.4 million.

Our findings enrich the limited evidence based on winter RODP, which is dwarfed by the extensive evidence based on summer RODP (DOE, 2006; Newsham and Bowker, 2010; Faruqui and Sergici, 2010; Faruqui and Palmer, 2012). They are of real-world relevance because an improved understanding of daily kWh responses to winter RODP helps BC to reliably meet its system peak demand caused by electric space heating in a cold winter evening. BC cannot adopt other winter-peaking regions' response estimates due to the differences in weather and customer attributes.[3] Nor can BC rely on the response estimates for a summer-peaking region, whose system peak demand is driven by air conditioning in a hot summer afternoon.

This paper makes three contributions to the RODP literature. First, it proposes a GL demand system to obtain empirically plausible winter daily kWh response estimates.[4] Second, the paper documents the dependence of the IHD's winter daily kWh effects on the price ratio. Finally,

2. We attribute the differences in the kWh response estimates to the differences between our data sample and those of the New Zealand and Ireland studies. For example, residents in BC tend to have larger homes and consume more electricity than those in New Zealand and Ireland. Reconciling the three sets of kWh response estimates, however, is beyond the scope of this paper.

3. For a discussion on the transferability of kWh response estimates, see Aigner and Leamer (1984), Caves et al. (1984) and Kohler and Mitchell (1984).

4. The GL specification has been used in residential TOU demand analyses (e.g., Parks and Weitzel, 1984; Caves et al., 1987). Our model formulation in Section 3 differs from theirs because of our interest in the estimated kWh effects and their variances in connection to the pilot's peak-to-off-peak price ratios and IHD.

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it applies the peak kWh response estimates to assess a system-wide RODP program's ability to reduce BC's peak capacity need.

The paper proceeds as follows. Section 2 describes the BC Hydro pilot. Section 3 presents the GL demand system. Section 4 reports our empirical results. Section 5 concludes. Finally, the paper has an appendix available from the first author, which provides supplemental information useful to practitioners of RODP.

2. BC HYDRO PILOT

2.1 Description

Serving 95% of BC's population of 4.63 million, BC Hydro has an installed generation capacity of about 12000 MW, 92% of which is hydro and the rest mainly natural-gas-fired. Its system peak is over 10000 MW, projected to grow by 40% over the next 20 years. It actively transacts in the wholesale markets of the winter-peaking Pacific Northwest (Woo et al., 2013c) and summer-peaking California (Woo et al., 2016). Its marginal cost during the winter peak period of 4–9 pm on a working weekday in November–February is more than twice that of the off-peak hours outside the peak period. However, BC Hydro's residential energy charge in 2006 was a non-TOU flat rate.

To learn residential kWh responses to TOU price signals, BC Hydro in September–October 2007 recruited 2070 opt-in participants living in single-family homes in Lower Mainland (major city: Vancouver), Fort St. John in Northern Interior and Campbell River on Vancouver Island. As these participants had mechanical meters that could only record their monthly kWh consumption, BC Hydro installed a digital interval meter to collect hourly kWh data at each participant's residence. Hence, BC Hydro did not collect pre-pilot hourly kWh data required by a difference-in-difference estimation of kWh responses to RODP, as exemplified by Di Cosmo et al. (2014), Carroll et al. (2014) and Jessoe and Rapson (2014).

To mitigate adverse selection by free riders who could obtain bill savings without changing their consumption behavior (Mackie-Mason, 1990; Woo et al., 1995), BC Hydro randomly assigned the participants into (a) a control group of 699 participants that continued to see the non-TOU flat rate; and (b) a treatment group of the remaining 1371 participants who faced five different TOU rate schedules in the winter months of November 2006–February 2007. For the non-winter months of March–October in 2007, all participants were billed at the non-TOU flat rate.

Each TOU participant received an upfront bill credit to mitigate the bill increase caused by the applicable TOU rate schedule. While the credit encouraged customer participation, its upfront nature and small size were not expected by BC Hydro to materially affect a participant's consumption behavior during the pilot's first winter in November 2006–February 2007.

A study by BC Hydro staff reports that some interval meters did not provide valid hourly kWh data in the pilot's first month of November 2006 (Sulyma et al., 2008). Using the daily kWh data by TOU for December 2006–February 2007, the same study finds that the treatment group's peak kWh was 9.6% less than the control group's peak kWh and the IHD did not have a conservation effect.

After the pilot's first winter, BC Hydro asked the participants to re-enroll, contributing to 1632 of the 1717 participants in the pilot's second winter of November 2007–February 2008. The remaining 85 participants were newly recruited for assessing the peak kWh effect of shortening the 4–9 pm peak period by one hour to 4–8 pm. This sample of 1717 participants is representative of BC Hydro's population of single-family-home customers, as shown by Table A.1 of the appendix.

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Table 1: Distribution of Voluntarily Participants of BC Hydro's Residential Optional Dynamic Pricing (RODP) Pilot

Rate schedule number: description; all prices in Canadian cents per kWh	Peak-to-off-peak price ratio	Lower Mainland: no IHD	Lower Mainland: IHD	Fort St. John: no IHD	Total
1101: Non-TOU; flat price = 6.33¢/kWh	1.0	284	0	33	317
1141: TOU; peak price = 19¢/kWh; off-peak price = 6.33¢/kWh	3.0	118	77	52	247
1141A: TOU (shortened peak period = 4–8 pm); peak price = 19¢/kWh; off-peak price = 6.33¢/kWh	3.0	83	2	0	85
1141B: CPP/TOU; CPP price = 50¢/kWh triggered with advanced notice by 5 pm the day before a CPP event; peak price = 19¢/kWh; off-peak price = 6.33¢/kWh	CPP: 7.9 TOU: 3.0	115	0	0	115
1142: TOU; peak price = 25¢/kWh; off-peak price = 6.33¢/kWh	3.9	183	76	59	318
1143: TOU; peak price = 28¢/kWh; off-peak price = 4.5¢/kWh	6.2	171	73	0	244
Total		954	228	144	1326

Table 1 shows that 228 of the 1326 participants in Lower Mainland and Fort St. John had IHD. Hence, 17% (= 228/1326) of the participants served as the IHD-treatment group and the remaining 83% the no-IHD-control group.

This paper's focus is the participants in Lower Mainland and Fort St. John observed over 83 working weekdays in the pilot's second winter.[5] Table 2 presents the descriptive statistics of our sample of non-missing customer-day observations based on the data file supplied by BC Hydro. It shows that the peak and off-peak kWh data are noisy. The remaining variables exhibit sufficient data variations for estimating their individual effects on a participant's daily TOU kWh.

2.2 Two Prior Studies of the Pilot's Second Winter

The first study is Woo et al. (2013a), an analysis of covariance (ANCOVA) of 24 hourly natural-log kWh regressions. It finds the peak kWh of the treatment group in Lower Mainland and Fort St. John 6% to 11% less than the control group's peak kWh and the IHD's kWh effect undiscernible. The second study is Woo et al. (2013b), documenting estimated elasticities of substitution of about 0.06 and peak kWh reductions of 4% to 9% for a price ratio change from 1.0 to a value of 3.0 to 11.0.

Several remarks can be made about these two studies. First, they report continued peak kWh reduction effects in the pilot's second winter, mitigating the concern of diminishing persistence raised by Houde et al. (2013) and Martin and Rivers (2015). Second, the estimated peak kWh reductions *sans* the IHD are less than those for New Zealand and Ireland, while corroborating the lower half of the range of estimates reported in several literature surveys.[6] Third, the IHD's undiscernible kWh effect counters the widely documented evidence.[7] Finally, the ANCOVA model in

5. BC Hydro did not supply the non-winter data because using the pooled data could be criticized for quantifying *winter* kWh responses based on a sample with 2/3 of the kWh data unrelated to BC's *winter* system conditions.

6. See Faruqui and Malko (1983), DOE (2006), Faruqui and Sergici (2010), Newsham and Bowker (2010), and Faruqui and Palmer (2012).

7. See Darby (2006), Faruqui et al. (2010), Delmas et al. (2013), Jessoe and Rapson (2014), Gans et al. (2013), Carroll et al. (2014), and Martin and Rivers (2015).

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Table 2: Descriptive Statistics of the 87361 Non-missing Customer-day Observations for Lower Mainland and Fort St. John in November 2007–December 2008

Definitions for (a) the left-hand-side (LHS) variables X_1 and X_2 of the GL demand regressions; and (b) the right-hand-side (RHS) variables listed below the row for X_2	Mean	Standard deviation	Minimum	Maximum
X_1 = Daily peak kWh on a working weekday in November 2007–December 2008	8.40	5.85	0.080	70.22
X_2 = Daily off-peak kWh on a working weekday in November 2007–December 2008	23.15	17.60	0.330	225.69
$(P_1/P_2)^{1/2}$ = Daily square root of the peak-to-off-peak price ratio used in equation (1.b)	1.927	0.407	1.000	2.810
$(P_2/P_1)^{1/2}$ = Daily square root of the off-peak-to-peak price ratio used in equation (1.a)	0.549	0.151	0.356	1.000
D = Daily binary indicator for the IHD's presence = 1 if yes, else 0	0.204	0.403	0	1.000
$(P_1/P_2)^{1/2} \times D$ used in equation (1.b)	0.425	0.847	0	2.494
$(P_2/P_1)^{1/2} \times D$ used in equation (1.a)	0.102	0.202	0	0.577
Daily binary indicator for the shortened peak period = 1 if yes, else 0	0.079	0.269	0	1.000
Daily customer size = Customer-specific kWh per calendar day for each month in November 2005–December 2006	32.38	20.46	0.167	213.40
Daily binary indicator for location = 1 if Lower Mainland, else 0	0.853	0.354	0	1.000
Daily binary indicator for primary electric heat = 1 if yes, else 0	0.055	0.229	0	1.000
Daily binary indicator for secondary electric heat = 1 if yes, else 0	0.343	0.474	0	1.000
Daily sum of heating degree hours = Daily sum of max(18^{0}C–hourly temperature, 0)	383.59	174.70	161.10	1235.40
Daily binary indicator for primary electric heat × Daily sum of heating degree hours	19.35	84.45	0	1235.40
Daily binary indicator for secondary electric heat × Daily sum of heating degree hours	125.89	196.75	0	1235.40

Note: For brevity, this table does not report the descriptive statistics for the binary indicators for day of week and month of year.

Woo et al. (2013a), while simple and easy to implement, may have contributed to the odd finding related to the IHD's kWh effect. The last two remarks motivate our reformulation of the kWh regression analysis, yielding estimated kWh responses that are useful for BC's resource planning and grid operation.

3. REGRESSION ANALYSIS

3.1 Rationale

The rationale for our proposed regression analysis is that the estimated kWh effects are useful for determining the cost saving per participant of a RODP program, which is the sum of (a) the expected winter peak kWh change per participant × BC Hydro's peak marginal cost, and (b) the expected winter off-peak kWh change per participant × BC Hydro's off-peak marginal cost; *minus* the sum of (c) incremental cost estimate for advanced metering infrastructure (AMI) per

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participant (= zero if AMI is already in place), and (d) incremental IHD cost estimate per participant (= zero if the installed AMI has an IHD feature).

When the RODP program has positive cost savings, it can be Pareto superior (Mackie-Mason, 1990; Woo et al., 1995, 2008). By revealed preference, voluntary participants are made better off by the program's implementation. The program's total cost saving (= saving per participant × number of participants) can be used to improve the utility's earnings and reduce the non-participants' rates.

The variances of the estimated kWh changes help determine the estimated cost saving's volatility. This volatility estimate can be used to establish the floor that the actual saving may exceed with a 95% probability, akin to the value-at-risk concept (Jorian, 2007) in the wholesale market pricing of an electricity forward contract (Woo et al., 2001, 2011).

A peak kWh response estimate's variance gauges RODP's reliability in delivering a peak kWh reduction. Suppose the peak kWh reduction estimate per participant for a CPP day is 2 kWh, with a 95% confidence interval of 1.5 kWh and 2.5 kWh. The lower bound of 1.5 kWh is the minimum kWh reduction that the actual reduction may exceed with a 97.5% probability.

3.2 Role of the Price Ratio

Our GL demand model assumes that a participant's peak and off-peak kWh move with the price ratio. This assumption's first justification is the rate design approach commonly used by an electric utility for a system-wide RODP program. To see this point, consider the example of a two-period TOU rate design with peak rate P_1 and off-peak rate P_2 that aim to achieve the existing average rate P paid by customers eligible for the program.

Using the hourly kWh data collected from a load-research sample of eligible customers, the utility first finds the sample's peak kWh share S_1 and the off-peak kWh share S_2. It then sets a price ratio R (e.g., 3.0) to find P_1 and P_2 based on $P = S_1P_1 + S_2P_2$, yielding $P_2 = P/(S_1R + S_2)$ and $P_1 = P-(S_2P_2/S_1)$. By varying R, the utility develops a list of TOU tariff candidates. The ultimately chosen TOU tariff is based on its cost saving and customer acceptance.

The assumption's second justification is the two-stage utility maximization model (Pollak and Wachter, 1975) used in TOU demand estimation (e.g., Lawrence and Aigner, 1979; Aigner, 1984). In the first stage, a residential customer minimizes the electricity cost for producing such end-use services as lighting, space and water heating, and refrigeration. In the second stage, the customer achieves budget-constrained utility maximization by selecting an optimal bundle of the domestically produced end-use services and other goods and services. Our GL model corresponds to the first-stage problem of electricity cost minimization, implying the peak and off-peak kWh are input demands that depend on the price ratio, rather than the peak and off-peak rates (Varian, 1984).

3.3 GL Specification

We adopt the GL specification (Diewert, 1971) due to its global properties as a flexible functional form for characterizing input demands with low elasticities of substitution (Caves and Christensen, 1980). Further, unlike other popular functional forms, the GL specification enables a linear estimation of the kWh response estimates listed below.[8] Most importantly, the results in

8. There are other commonly used functional forms, all of which yield kWh effect estimates that are nonlinear in the regression coefficient estimates. For example, the Constant Elasticity of Substitution (CES) yields a regression model that relates the natural-log of the peak-to-off-peak kWh ratio to the natural-log of the peak-to-off-peak price ratio (Varian, 1984).

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Section 4 suggest that the GL specification leads to empirical demand curves suitable for estimating the kWh responses.

Let X_1 = daily peak kWh on a working weekday, X_2 = daily off-peak kWh on the same day, and $D = 1$ if IHD present, 0 otherwise. With coefficient estimates (b_{1D}, b_{2D}, b_{12}, b_{12D}), the estimated GL peak and off-peak kWh regressions are:

$$X_1 = b_{1D}\, D + b_{12}\, (P_2/P_1)^{1/2} + b_{12D}\, (P_2/P_1)^{1/2} D + \text{kWh effects of other variables;} \qquad (1.a)$$

$$X_2 = b_{2D}\, D + b_{12}\, (P_1/P_2)^{1/2} + b_{12D}\, (P_1/P_2)^{1/2} D + \text{kWh effects of other variables.} \qquad (1.b)$$

A well-behaved GL cost function is concave in the peak and off-peak rates, implying that b_{12} and b_{12D} should be positive (Diewert, 1971). As $b_{12D} \geq 0$, the IHD's conservation effect requires $(b_{1D} + b_{2D}) \leq 0$, as shown by equation (4) below.

The kWh effects of other variables in equations (1.a) and (1.b) are related to two sets of regressors based on the data readily available to BC Hydro.[9] The first set contains binary indictors for the day of week, the month of year, the shortened peak period, as well as a participant's location and use of electric space heating.

The second set has two metric variables. The first variable is a participant's daily local weather = daily sum of heating degree hours, with each heating degree hour = max(18°C − hourly local temperature, 0). The second variable is a participant's size in a given month (e.g., November), measured by the participant's kWh consumption per calendar day two years ago. As the size data were recorded well before the pilot's commencement in November 2006, they are exogenous.

As described in the appendix, we jointly estimate equations (1.a) and (1.b) as a system of seemingly unrelated regressions. We use customer-clustered standard errors to measure the coefficient estimates' precision, reflecting the panel nature of our sample of customer-day observations (Wooldridge, 2010).

3.4 kWh Effects of RODP

We focus on the peak kWh response estimate per working weekday because the estimate aids capacity planning. The response is caused by an increase in the price ratio from 1.0 for a non-TOU flat rate to $(P_1/P_2) \in \{2, 3, 4, 5, 6\}$ for a non-CPP weekday and to $(P_1/P_2) \in \{8, 9, 10, 11, 12\}$ for a CPP day. These two ranges mirror the price ratios likely acceptable to BC residents and those used by 74 dynamic pricing programs (Faruqui and Palmer, 2012, Figure 5).

Based on equations (1.a), the estimate *sans* an IHD due to a price ratio change from 1.0 to $(P_1/P_2) \geq 2$ is:

$$\text{Peak kWh response} = b_{12}\, [(P_2/P_1)^{1/2} - 1]; \qquad (2)$$

The Translog and AIDS lead to regressions relating the cost shares by TOU period to the natural-log of price ratios (Deaton and Muellbauer, 1980).

9. For a targeted implementation of a RODP program, BC Hydro can only use its billing database to obtain information on a potential participant's size, dwelling type, location and use of electric heating. BC Hydro does not know each eligible customer's demographic information of age, education, income, family size, or house size.

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Table 3: Regression Results for Equations (1.a) and (1.b) Based on 87361 Non-missing Customer-Day Observations in November 2007–February 2008

Estimate	Peak kWh regression	Off-peak kWh regression
Adjusted R^2	0.6501	0.7843
b_{1D}	−0.4435*** (0.1661)	
b_{2D}		−1.9626*** (0.6767)
b_{12}	0.7325*** (0.0568)	0.7325*** (0.0568)
b_{12D}	0.5401* (0.3271)	0.5401* (0.3271)

Notes: (1) Customer-clustered standard errors in ( ); "*" = "significant at the 0.10 level", "**" = "significant at the 0.05 level", "***" = "significant at the 0.01 level".
(2) A participant's daily kWh by TOU are found to increase with cold weather, electric space heating and customer size and vary by day-of-week, month-of-year, and location. While mostly significant at the 0.05 level, these estimated kWh effects are omitted here for brevity.

As $b_{12} \geq 0$ and $(P_2/P_1)^{1/2} < 1$, equation (2) shows that the price ratio change tends to reduce the peak kWh. In the presence of an IHD, the estimate becomes:

$$\text{Peak kWh response} = (b_{12} + b_{12D})\ [(P_2/P_1)^{1/2} - 1]; \tag{3}$$

Because $b_{12D} \geq 0$, equation (3) shows that the IHD magnifies the peak kWh response.

Using equations (1.a) and (1.b), we find:

$$\text{Total kWh effect of the IHD} = (b_{1D} + b_{2D}) + b_{12D}\ [(P_2/P_1)^{1/2} + (P_1/P_2)^{1/2}]. \tag{4}$$

Since the last term in equation (4) is positive, $(b_{1D} + b_{2D})$ needs to be negative for the IHD to have a conservation effect.

As the price ratio is a rate design parameter, each of the estimated kWh responses given by equations (2)–(4) is a linear function of the coefficient estimate(s), with a variance that can be readily found using the formula in Mood et al. (1974, pp.179–180).

4. RESULTS

Table 3 reports our estimated kWh regressions. Both b_{12} and b_{12D} are positive, thus suggesting an IHD-aided RODP program's ability to reduce a participant's peak kWh. The negative b_{1D} and b_{2D} presage the IHD's conservation effects.

Figure 1 portrays the estimated peak kWh responses to a change of the price ratio from 1.0 under the flat rate to 2.0 to 6.0 under TOU pricing. The peak kWh reduction estimates *sans* IHD are 2.2% to 4.4% of the control group's peak kWh on a weekday. The IHD approximately doubles these reduction estimates.

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Figure 1: Estimated Reduction in Daily Peak kWh and Its 95% Confidence Interval due to a Peak-to-Off-peak Price Ratio Change under TOU Pricing from 1 to $(P_1/P_2) \in \{2, 3, 4, 5, 6\}$

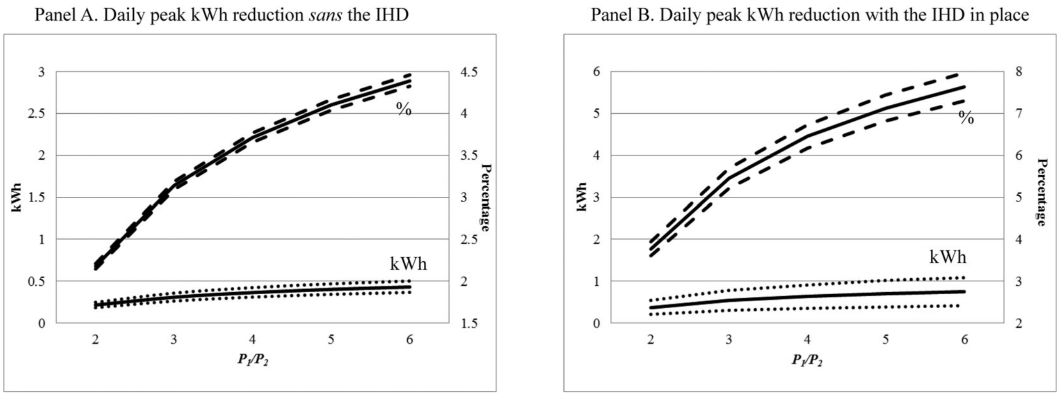

Figure 2: Estimated Reduction in Peak kWh on a CPP-Event Day and Its 95% Confidence Interval due to a Peak-to-Off-peak Price Ratio Change from 1 to $(P_1/P_2) \in \{8, 9, 10, 11, 12\}$

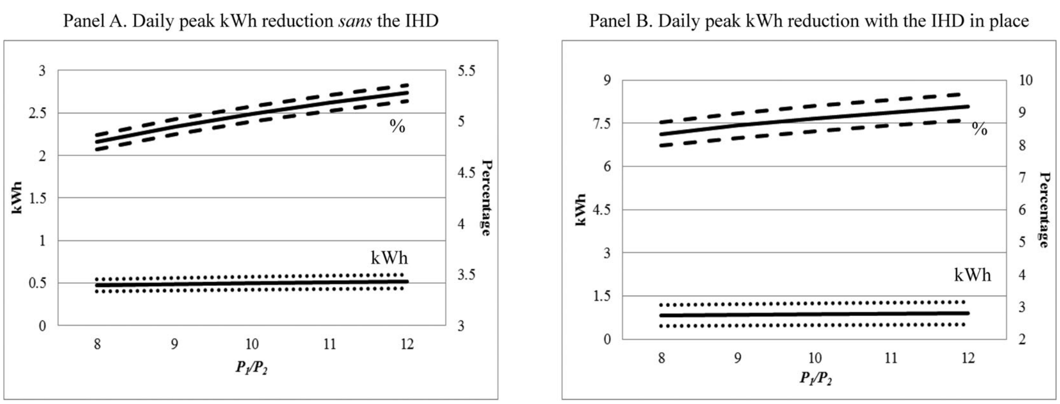

Figure 2 shows the estimated effect of a CPP ratio of 8.0 to 12.0. These estimates sans the IHD are 4.8% to 5.3% of the control group's peak kWh on a weekday. With the IHD in place, these estimates approximately double in size.

Figure 3 reports the IHD's estimated conservation effects at the TOU price ratios of 2.0 to 6.0. Declining with the price ratio, these effects are 2.4% and 3.5% of the control group's total kWh on a weekday.

In summary, these figures illustrate that winter RODP can achieve peak kWh reduction and conservation in BC, which can be further enhanced by the IHD.

5. CONCLUSION

We conclude with an application of our peak kWh estimates. Table 4 reports the estimated peak MW reductions of a system-wide IHD-aided RODP program. At the median peak kWh esti-

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Figure 3: Estimated Daily Conservation Effect of the IHD and Its 95% Confidence Interval at a TOU Peak-to-Off-peak Price Ratio (P_1/P_2) ∈ {2, 3, 4, 5, 6}

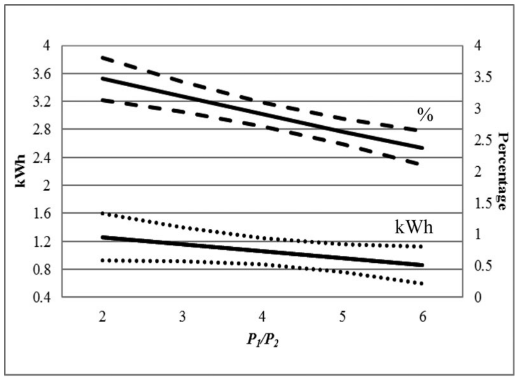

Table 4: Estimated Peak MW Reductions due to A System-wide RODP Program's CPP Peak-to-off-peak Price Ratio of 8.0

Without IHD			With IHD		
Peak kWh reduction per participant	Low opt-in participation rate: 10%	High opt-in participation rate: 30%	Peak kWh reduction per participant	Low opt-in participation rate: 10%	High opt-in participation rate: 30%
High: 0.55kWh	7.64	22.91	High: 1.19 kWh	16.61	49.84
Median: 0.47kWh	6.63	19.89	Median: 0.82 kWh	11.52	34.55
Low: 0.40kWh	5.62	16.87	Low: 0.46 kWh	6.42	19.27

Notes: (1) The formula is Peak MW reduction = [(Peak kWh reduction per participant on a winter working weekday/5 peak hours per working weekday) ÷ 1000 kW per MW] × Number of eligible customers × Participation rate.
(2) The peak kWh reduction per participant without IHD is based on equation (2) and with IHD equation (3). The high, median and low values are based on the peak kWh reduction's 95% confidence interval at the 8.0 price ratio in Figure 2.
(3) The assumed number of eligible customers is 0.7 million based on (a) an eligibility criterion of 1000 kWh consumption per winter month; (b) BC Hydro's Residential Inclining Block Application filed in February 2008 to the BCUC, which reports that BC Hydro had approximately 1.4 million residential customers in 2007, about half of whom with kWh consumption above 1000 kWh per winter month. The 1000-kWh criterion is chosen to match the average pre-pilot total consumption of 970 kWh per winter month of a residential customer participated in the pilot, so as to preempt the criticism that our peak kWh response estimates may not apply to small customers absent in our estimation sample (e.g., apartment residents without electric heating).
(4) The assumed opt-in participation rates are based on: (a) the 25% participation rate in Ontario Energy Board Smart Price Pilot Final Report, July 2007; and (b) the first author's personal communications with BC Hydro staff in 2009 in connection to a business case study of BC Hydro's Smart Metering Initiative.

mates, the program's projected cost saving is C$24.4 million to C$73.4 million.[10] As BC residents already have smart meters with an IHD function,[11] the policy implication is to explore using RODP to reduce BC's peak capacity need.

We would be remiss had we failed to acknowledge the following caveats. First, the estimated peak kWh reduction per participant might decline with the participation rate due to law of diminishing returns. This motivates collecting customer participation decision data to account for the sample selection bias caused by voluntary participation (Heckman, 1979; Aigner and Ghali, 1989).

Second, this paper is a snapshot of the winter consumption behavior of the BC participants. It ignores the Hawthorne effect due to the participants knowing that they were in a pilot project under observation (Martin and Rivers, 2015). Hence, an area of future research is to estimate the GL demand model using data from a system-wide RODP program implemented on a permanent basis.

Finally, our estimated kWh responses based on the BC pilot's second winter may differ from those found using data that span several years (Martin and Rivers, 2015). Once in place, however, a permanent RODP program can generate the data required to identify its long-run kWh effects via electricity demand estimation (e.g., Taylor and Schwarz, 1990; Taylor, et al., 2005).

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10. Since the projected peak MW reduction is 11.5 MW to 34.6 MW, the associated reduction in BC's capacity need is 13.2 MW to 39.8 MW, thereby accounting for the planning reserve requirement equal to 15% of BC's system peak. Using the plant cost data in CEC (2010), the total cost saving is the sum of (1) the initial capital saving is C$19.8 million to C$59.7 million at an assumed cost of C$1500 per kW installed for natural-gas-fired generation, and (2) the present value of annual fixed O&M cost savings is C$4.6 million to C$13.7 million based on the assumed fixed O&M cost of $30/kW-year, useful life of 20 years and discount rate of 6%/year.

11. As of April 2016, BC Hydro has "installed 1.9 million new electricity meters called 'smart meters'—the new standard for the BC Hydro system" (https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-meters.html).

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