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Review of Residential Time-Varying Rate Pilot Projects and Programs: Effects in Winter

Guy R. Newsham

National Research Council Canada
Conseil national de recherches Canada

Canada

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Executive Summary

Natural Resources Canada (NRCan) is now funding NB Power and Nova Scotia Power to conduct demonstration projects to explore the potential of tariffs, controls, and distributed energy resources (DERs) to support smart grid development, and building codes to underpin the smart grid of the future. NB Power's part of this project will take place in the township of Shediac, and NB Power will partner with NRC on the experimental design, data collection and analysis aspects of this project.

A primary component of this project is a 500-home pilot exploring time varying rate (TVR) structures, load control, generation, and storage. In this report we review the prior use of TVRs elsewhere in contexts relevant to the New Brunswick project, to help:

- Inform the choice of an experimental rate structure for the Shediac pilot
- Choose actions that will support a successful deployment of the new rate structure
- Anticipate potential customer reactions

From this review, several general themes emerged:

- Utilities typically design TVR to be revenue neutral, that is the average customer, if they do not change their behaviour, will not receive a higher total electricity bill under TVR compared to the standard fixed rate. Of course, some customers may get higher bills due to their particular use profiles, in these cases, and when TVR is applied in a pilot project, utilities typically offer some form of bill protection.
- Low-income customers may need specific consideration, as any risk of a bill increase represents a greater fraction of their available income and, further, they may lack the resources to invest in measures to lower consumption during peak periods.
- TVR almost always resulted in a reduction in average peak period usage, although the reduction was sometimes only a few percent. There was also sometimes a small overall conservation effect.
- Higher ratios between peak and off-peak prices are often associated with higher peak use reductions.
- Commercial deployments of TVR are usually offered on an opt-in basis.
- The primary motivation for customers to opt-in to TVR studies or programs was the desire to save money, environmental considerations were typically a distant second.

Strategies have been identified that make TVR programs (and other DR approaches) more likely to succeed. These include simple tariffs, enabling technology, education, and feedback. Customer segmentation may also help, with invitations to opt-in to pilots and programs tailored to specific customer characteristics. More frequent interaction (e.g. interviews, meetings, questionnaires) with participants in pilot studies also tended to improve results. It is also it is very important to manage customer expectations around potential bill savings.

1 Introduction

1.1 Shediac Project

NB Power has a vision for a smart grid in New Brunswick that will enable a more cost-effective and reliable supply of electricity to its customers, and a greater fraction of renewables in the supply mix; Siemens is their primary industry partner in this endeavour. To this end, NB Power has conducted multiple pilot studies to better inform policy and program development. These studies have included projects with NRC exploring the use of smart thermostats to shift heating load away from peak periods [Pardasani et al., 2016, 2018, 2019], and a project on conservation voltage regulation (CVR).

Natural Resources Canada (NRCan) is now funding NB Power and Nova Scotia Power to conduct demonstration projects to explore the potential of tariffs, controls, and distributed energy resources (DERs) to support smart grid development, and building codes to underpin the smart grid of the future. NB Power's part of this project will take place in the township of Shediac, and NB Power will partner with NRC on the experimental design, data collection and analysis aspects of this project, particularly with respect to the residential aspects of the work.

For NB Power, primary components include deployment and operation of:

- Two community-scale solar installations – one with battery storage
- One municipal and one federal government office building with varying DER configurations
- A 500-home pilot exploring time varying rate structures, load control, generation, and storage

NRC will be primarily responsible for the design of the residential pilot study, analysis of data from smart meters, energy management systems, designing and administering customer surveys, and analysing customer feedback on programs.

In the residential pilot study, the participating households will be divided into several groups, each getting a unique combination of "treatments" (one or more new: electricity rate structures, building system controls, or equipment packages), plus a control (or non-treatment) group that will receive no change in their electricity supply agreement with NB Power and no new equipment. It is expected that one or more of these treatment groups will be exposed to a new time varying rate (TVR) for electricity, perhaps in combination with other measures. In this report we review the prior use of TVRs elsewhere in contexts relevant to the New Brunswick project, to help:

- Inform the choice of an experimental rate structure for the Shediac pilot
- Choose actions that will support a successful deployment of the new rate structure
- Anticipate potential customer reactions.

1.2 Time Varying Rates (TVR)

TVR is a generic term to describe rate structures for the commodity portion[1] of a customer's electricity bill in which the price of a kilowatt-hour (kWh) varies by time of day, day of week, or season of year, compared to the standard fixed rates[2] that have typically prevailed for decades. It is hypothesized that exposing customers to rates that more closely resemble the instantaneous cost of production will drive behaviour change to lower use of electricity during expensive (peak) periods and, perhaps, to conservation overall. With the goal of peak load reduction, TVR is one element of the larger set of strategies called demand response (DR), where utilities and system operators balance load on the grid by modifying demand as well as supply; reducing demand is typically a much cheaper alternative to building additional supply capacity. The option for utilities to develop these alternative tariffs is facilitated by the roll-out of advanced metering infrastructure (AMI), or "smart meters" that record total residential electricity use on an hourly or sub-hourly basis. Indeed, the potential to deploy TVR, and the anticipated peak reduction and conservation effects, are often one element of the business case for AMI deployment [e.g., BC Hydro].

1.2.1 TVR Definitions

The following definitions for the primary TVR options that have been piloted and deployed by utilities in North America and elsewhere are based on those provided by Faruqui et al. [2012][3].

Time-Of-Use (TOU): A static TOU rate divides the day into time periods and provides a schedule of rates for each period. For example, a peak period might be defined as the period from 2 – 6 PM on weekdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the average (but not real-time) variation in the cost of supply. In some cases, TOU rates may have a shoulder (or mid-peak) period, or even two peak periods (such as a morning peak from 8 – 10 AM, and an afternoon peak from 2 – 6 PM). Additionally, the prices and periods might vary by season. With a TOU rate, there is certainty as to what the rates will be and when they will occur.

Critical Peak Pricing (CPP): Under a CPP rate, participating customers pay (much) higher prices during the few hours/days of the year when market prices are the highest or when the power grid is severely stressed. In return, the participants typically receive a discount on the standard tariff price during the other hours of the season or year to keep the utility's total annual revenue constant. Customers are typically notified of an upcoming "critical peak event" one day in advance.

Critical Peak Rebate (CPR): Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours.

Real Time Pricing (RTP): Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Therefore rates are potentially different at every hour and on every day. Participants are made aware of hourly prices in advance, which can be day-ahead or hour-ahead.

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[1] The total cost on a customer's bill will usually also include fixed charges which are not proportional to usage, and taxes. In many jurisdictions the non-commodity portion of the bill can comprise a substantial fraction of the total.

[2] This is a fixed charge per kWh regardless of time of use. In some cases the fixed charge is tiered or "blocked", with one rate up to a specific total usage in a billing period (usually a month), and another rate for kWh used beyond this value.

[3] See also Darby & McKenna [2012], and Baatz [2017].

Beyond these four popular pricing approaches there are further variations that are described under the specific pilot and program descriptions below, as applicable.

2 Summaries of Related Work

There have been many TVR pilots and some full implementations across multiple countries; in some cases TVR is combined with electricity use feedback mechanisms or programmable load control devices, or both. However, the large majority of these prior deployments have been in summer peaking regions (where the target has been the reduction of air conditioning load during periods of peak systemwide demand), and where the primary winter heating fuel is natural gas. In other words, most deployments were in contexts with little direct relevance to the New Brunswick situation. A good summary of these studies is Faruqui et al. [2017] and Newsham & Bowker [2010]. However, the scope of this report is on the smaller sub-set of deployments with applicability to the New Brunswick context, many of which are not described in Faruqui et al. [2017] and Newsham & Bowker [2010]. Ideally, we would like to learn from studies from winter peaking locations, with electric heat and very cold winters. However, such studies are very small in number, so this review also includes locations that are winter peaking but with milder winters or without primary electric heat; we also include some studies from summer peaking locations that also reported winter effects.

To broaden the potential learning, we searched for studies in developed economies from all over the world. We included peer-reviewed articles from scientific journals and conferences, as well as utility (or similar) reports where the methods and analyses were credibly documented. We judged that more recent studies would be more relevant, and used 2010 as a rough cut-off publication date, although these publications may refer to data recorded earlier than this, and we did consider some earlier work if it was highly relevant.

In this section each study is briefly summarized, and the bibliographic citation is provided if the reader would like more detail. Studies are grouped geographically, starting with locations closest to New Brunswick, regions with electricity contexts most similar to New Brunswick are also shown first.

In the summaries below Prices from studies in Canada, the US and Australasia are expressed in local currency (C$, US$, NZ$, AUS$), which are all local dollars are cents. Prices from studies in Europe are converted from the local currency quoted in the original sources into Canadian currency using exchange rates that applied at the time of the study.

Table 1 summarizes the TVR studies with measured TOU effects (winter focus) in percentage terms. The sections following Table provide more detail on these studies, as well as descriptions of several other relevant studies and programs using different TVR approaches and with TOU effects expressed via different metrics.

Table 1. Summary of relevant TVR studies with measured results for TOU aspects, winter effects.

Location	Example TOU on-peak rate (¢/kwh)	Example TOU off-peak rate (¢/kwh)	TOU on-peak reduction (%)
BC, Canada	28	4.55	11.1
Ontario, Canada	14.0	7.7	0.5 – 2.5
California, USA	27.3	22.7	1.5 – 3.5
Norway	17.5	0.6	1.8
Denmark	9.1	1.4	2.0
Italy	?	?	2.9
Germany	36.5	20.7	6 – 7
Ireland	30.3	13.6	8.8
Cyprus	27.7	16.0	1.4
New Zealand	29.0	9.0	10.0

2.1 Canada

2.1.1 Quebec

Arguably the context most similar to that of New Brunswick is Quebec, in being Canadian, winter peaking in very cold winters, and mostly electric heating. However, we were unable to locate documentation of any prior studies of TVR in Quebec. Nevertheless, Hydro Quebec recently announced a partial roll-out of two new rate options, the Winter Credit Option and Rate Flex D, to apply in the winter of 2019-20[4], which we describe here because of their high relevance. These will be opt-in programs, and will be limited to 18,000 residential and farm customers in the first year. Both of these rates are designed to reduce load during specific forecasted peak events, and customers will notified of such events by 5 PM of the day before. Peak events can occur only between December 1st – March 31st, from 6 – 9 AM and 4 – 8 PM, with 25 – 33 events per winter, for a maximum of 100 hours in total. Winter Credit customers will pay the standard price at all non-event times (6.08 ¢/kWh for the first 40 kWh/day and 9.38 ¢/kWh for the remainder); events may occur on any day of the week, and they will receive a 50 ¢ bill credit for every kWh curtailed (compared to a calculated baseline for the customer) during an event period. Rate Flex D customers will pay the standard price at all non-event times in the summer, and a lower rate at non-event times in the winter (4.28 ¢/kWh for the first 40 kWh/day and 7.36 ¢/kWh for the remainder); events may occur on Mondays – Fridays only, and they will pay 50 ¢/kWh during an event period. Therefore, Winter Credit customers can only save money compared to the standard rate, whereas Rate Flex D customers have a greater potential for savings if they shift enough load outside of winter peak hours, but can also pay more than the standard rate if they concentrate usage in peak hours.

2.1.2 British Columbia

BC is a winter peaking province, and although there are regions in which residential heating is primarily electric, such heating is in the minority province-wide; further, BC's winters are relatively mild by Canadian standards. Several publications describe TVR pilots conducted by BC Hydro.

Tiedemann et al. [2007], Tiedemann [2009] and Tiedemann & Sulyma [2010] describe an opt-in randomized control experiment in which treatment houses (N=1306) were exposed to TOU rates (designed to be revenue neutral)[5], received information on how they could save or shift energy from the peak period, and had on-line access to their own energy usage. There were seven different TOU structures, some had an evening peak (4 – 9 PM) only, and others both a morning (8 – 11 AM) and an evening peak (4 – 8 PM); the off-peak rate was 4.55 or 6.33 ¢/kWh, whereas as the on-peak rate was 15 – 28 ¢/kWh; two structures also featured a CPP rate of 50 ¢/kWh. The control group (N=411) received no information and stayed with standard rates (6.33 ¢/kWh). The treatment group exhibited 11.1% lower energy use on-peak, and 3.2% lower use off-peak, and reported substantially more energy efficient behaviours (particularly with respect to thermostat setting) than the control group.

Woo et al. [2013a, 2016] conducted further analyses on these experimental data, and, in particular, estimated the effect of the CPP rate. There were eight CPP events, which were announced by 5 PM on the day before. CPP was associated with an additional on-peak reduction of 9%. Some customers (N=44) had remotely activated load control devices that automatically responded to CPP events; these devices included cycling of baseboard space heaters and water heaters, or a smart thermostat for central heating. These load control devices were associated with an additional 25% on-peak reduction. In addition, they found that information and feedback alone did not realise any evening peak reduction. Woo et al. [2013b] evaluated the effect of the

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[4] http://www.hydroquebec.com/residential/customer-space/rates/dynamic-pricing.html

[5] An upfront payment was also offered to offset any estimated bill increase from TOU rates.

varying price ratios in the various TOU structures. They found that, without load control, a peak-to-off-peak price ratio of 2:1 yielded a peak reduction of 2.6%, whereas a price ratio of 12:1 yielded a reduction of 9.2%; with load control these estimates were 9.2% and 30.7%, respectively.

2.1.3 Ontario

Ontario is a summer peaking province, and the vast majority of residential customers heat with natural gas. Ontario was relatively unusual worldwide, at time of writing, in having mandatory TOU for all residential customers[6]. Several studies have been conducted to evaluate the effect of TOU pricing on peak reduction and energy conservation, some of which estimate winter effects.

Navigant [2010] completed an analysis for a single Local Distribution Company (LDC). Hourly electricity use data over an 833 day-period were analyzed. There were three experimental groups (N=690, 840, 762) that were switched from the prior regulated price plan (RPP) to TOU in various date blocks, and a control group (N=883) that did not switch to TOU rates until after the period of analysis. The overall analysis period covered April 1st, 2007 – July 12th, 2009, and there was variation in both RPP and TOU rates in this period. The winter season was defined as November 1st – April 30th. RPP customers were charged approximately 5.4 ¢/kWh for the first 1000 kWh/month in winter and 6.3 ¢/kWh for the remainder[7]. TOU customers were charged approximately 9.1 ¢/kWh on-peak (in winter, 7 – 11 AM and 5 – 8 PM weekdays), 7.2 ¢/kWh mid-peak (11 AM – 5 PM and 8 – 10 PM weekdays), and 3.4 ¢/kWh off-peak (10 PM – 7 AM weekdays, and all day weekends and holidays)[8]. Analysis indicated that in winter there was an average reduction in electricity use in the mid-peak period of 2.6 %, and no reductions in other periods (and hence an overall conservation effect too)[9]. A survey following the consumption study (N=310) was conducted, and, interestingly, customers who demonstrated perfect recall of the on-peak periods exhibited a much greater on-peak reduction than the average experimental customer, however, this group was very small in the analysis (N=17).

Faruqui et al. [2016] analyzed data from 102,769 residential customers (including 4,028 retail customers) from four LDCs[10], from the inception of TOU rates (starting in 2009) to the end of 2014. By this time the TOU rate structure had been modified compared to the earlier study by Navigant [2010]: on-peak (in winter, 7 – 11 AM and 5 – 7 PM weekdays), mid-peak (11 AM – 5 PM weekdays), and off-peak (9 PM – 7 AM and 7 PM – 9 PM weekdays, and all day weekends and holidays)[11]. TOU prices varied over the time of the study (with a general trend upwards), but, as an illustration, the commodity rates in November 2014, at the end of the analysis period, were: 7.7 ¢/kWh, 11.4 ¢/kWh, and 14.0 ¢/kWh, for off-peak, mid-peak and on-peak, respectively. In the context of this report, we focus on the segmented winter results from the sub-sample of customers in the north of the province (N=12,401), which had the coldest winters, and a higher fraction of electric heating [FAO, 2016]. Use reductions in the pre-2012 period were 2.55 % and 2.17 % in the morning and evening winter peak

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[6] Mandatory TOU is expected soon in several major US states [Baatz, 2017], but note that EURELECTRIC [2017] argues, in the European context, that all TVR should be opt-in.
[7] The threshold was 600 kWh/month in the summer.
[8] The corresponding schedule in summer was on-peak, 11 – 5 PM weekdays; mid-peak, 7 – 11 AM and 5 – 10 PM weekdays; and off-peak, 10 PM – 7 AM weekdays, and all day weekends and holidays.
[9] The only significant summer reduction (5.4 %) was in the on-peak period, 11 AM – 5 PM, which was the same as the mid-peak period in winter. It is possible that the winter reduction was a consequence of occupants continuing conservation behaviours adopted in the summer.
[10] One of these LDC samples included the data analyzed by Navigant [2010].
[11] The corresponding schedule in summer was on-peak, 11 – 5 PM weekdays; mid-peak, 7 – 11 AM and 5 – 7 PM weekdays; and off-peak, 9 PM – 7 AM and 7 PM – 9 PM weekdays, and all day weekends and holidays.

periods, respectively, falling to 0.97 % and 0.50 % by 2014. Although effects declined over time, in 2014 the effects were substantially higher than for other regions in the province.

The Ontario Energy Board has recently launched three new pricing pilots with three LDCs. These include various TOU, CPP and other dynamic pricing options, with supporting control technology in some cases. Interim results have been reported for summer only to date[12], but winter results are promised in the future.

2.2 Other countries

2.2.1 United States

Many pricing pilots have been conducted in the United States. However, the primary goal of almost all of these studies has been on reducing electricity use during summer peak periods, and the main mechanism for this has been manual or automated control of air-conditioning. The scope of this report is not broad enough to encompass much of this work, but a good summary is available in Faruqui et al., [2017] and Newsham & Bowker [2010]. Here we only summarize studies that report on effects in winter, even if the primary heating fuel was natural gas.

Wolak [2010, 2011] describes a dynamic pricing experiment in Washington, DC, and, with relevance to our report, breaks out results for all-electric customers in winter (2008/9). Customers were randomly selected into three treatment groups: CPP (N=236), CPR (N=387), and hourly pricing (HP, N=234, similar to RTP) – and a control group (N=388). All treatment groups also received additional detailed energy use reports. CPP and HP customers received a $100 payment to compensate them for any risk of an increased bill. Across all treatment groups 215 customers were all-electric, including electric heating. Three CPP events were called in the designated winter period (November 1st – February 28th), and notifications were sent to customers by 5 PM the day before; winter CPP event periods were 6 – 8 AM and 6 – 8 PM. Events were called based on low day-ahead outdoor temperature forecasts; the mean actual temperatures during the CPP events were -5.1, -10.8, and -2.2 °C, respectively. All-electric control group and CPR customers paid an increasing block rate of 12.8 ¢/kWh for the first 400 kWh and 14.7 ¢/kWh for the remainder. CPP customers faced a slightly lower increasing block for their usage outside of winter event hours – 11.6 and 12.1 ¢/kWh, respectively – but were charged 70.2 and 70.7 ¢/kWh, respectively, for usage during peak events. In contrast, all-electric CPR customers during peak events received a rebate of 64.9 and 63.1 ¢/kWh, respectively, for usage below their individual baseline. Customers were not told how the baseline was calculated due to concerns that it might induce manipulation, but it was the average of the usage during 6 – 8 AM and 6 – 8 PM on the three highest consumption non-holiday weekdays in the same month. HP customers paid prices posted one day ahead and based on the prevailing wholesale market rates. If the next-day price exceeded 15 ¢/kWh an alert was sent to HP customers identifying the specific high-price hours; there were a total of 38 such "warning" hours in the sample period. Results showed that in the winter, and among all-electric customers only, the HP treatment was associated with a reduction of 32.3 % in consumption during warning hours. For CPP events, CPP customers demonstrated a reduction of 21.6 % in consumption during event hours, whereas the CPR group exhibited no statistically significant effect.

Elevate Energy [2015] report on an opt-in RTP program deployed in Illinois since 2007 (N=11,586 at the end of 2014). Over the lifetime of the program average hourly RTP prices have been lower than the standard fixed rate, although the reverse was true during the severe winter in the first quarter of 2014, and following a drop in the fixed rate. For example, standard fixed rates in 2014 were 4.3 ¢/kWh from January – May, and 3.9 ¢/kWh thereafter; the average day-ahead RTP was 5.1 ¢/kWh in January, 3.9 ¢/kWh in May, and 2.8 ¢/kWh in

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[12] https://www.oeb.ca/industry/policy-initiatives-and-consultations/rpp-roadmap

December. RTP participants were alerted the day before when one or more hours the next day would exceed 9 ¢/kWh, this occurred 21 times in the first quarter of 2014 on days when the average windchill was -12 ºC; there were no winter price alerts in any prior year. The highest hourly price in the winter of 2014 was 34.3 ¢/kWh, whereas the highest price in summer was 9.2 ¢/kWh. Electric space heat customers were estimated to have reduced their load by an average of 70 W/customer on 2014 alert days, although, since 2011, those same customers had used 2.4% more electricity overall. As a result of higher overall prices in 2014, RTP participants paid 18.6% more for the commodity portion of their bill than fixed rate customers, although over the life of the program they have paid 18% less in aggregate. In a participant survey 75% reported being “satisfied” or “very satisfied” with the RTP program. By far the most common reason for participating in the program was bill savings, with environmental concerns a distant second. We can infer from the data presented that most electric space heating participants reduced their thermostat settings in response to high winter prices.

George et al. [2018] report the findings from an opt-in TOU pricing pilot conducted by three California utilities, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Each utility tested three different TOU rates, and for eight of the nine rates more than 50,000 households were assigned to the treatment group or were retained in control groups on the standard tiered rates. For all utilities TOU Rates 1 and 3 had a peak period 4 – 9 PM, whereas Rate 2 had a peak period 6 – 9 PM. Focussing on the winter period only, for PG&E Rates 1 and 3 the off-peak rate was 26.1 ¢/kWh, and the peak rate (weekdays only) was 28.0 ¢/kWh; for Rate 2 the off-peak rate was 26.0 ¢/kWh, and the peak rate (all days) was 28.6 ¢/kWh. For SCE Rate 1 the off-peak rate was 22.7 ¢/kWh, and the peak rate (weekdays only) was 27.3 ¢/kWh; for Rate 2 the off-peak rate was 25.5 ¢/kWh, and the peak rate (weekdays only) was 27.6 ¢/kWh, and there was a Super Off-Peak rate (11 PM – 9 AM) of 17.7 ¢/kWh; for Rate 3 the off-peak rate was 18.3 ¢/kWh, and the peak rate (all days) was 21.1 ¢/kWh, and there was a Super Off-Peak rate on weekends (noon – 4 PM) of 10.4 ¢/kWh. For SDG&E Rate 1 the off-peak rate was 40.0 ¢/kWh, and the peak rate (weekdays only) was 41.0 ¢/kWh, and there was a Super Off-Peak rate (midnight – 7 AM weekdays, midnight – 2 PM weekends) of 39 ¢/kWh; for Rate 2 the off-peak rate was 39.0 ¢/kWh, and the peak rate (all days) was 41.0 ¢/kWh[13]. Standard tiered rates were founded on a baseline allowance, which is an allotment of energy available at the lowest price, based on location and heating source. For PG&E, control customers paid 20.0 ¢/kWh up to 100% of their baseline, and 27.6 ¢/kWh up to 200%; the respective rates for SCE were 16.3 ¢/kWh and 24.9 ¢/kWh, and for SDG&E 20.0 ¢/kWh up to 130% of baseline, and 40.0 ¢/kWh thereafter. Average winter (2016/17) peak period load reductions were, for PG&E 3.6%, 3.6%, and 3.5% for Rates 1, 2, and 3, respectively; for SCE reductions were 1.4%, 2.0%, and 3.2%; and for SDG&E 2.3% and 1.7%. Although these effects were smaller than summer effects, they are noteworthy considering the relatively low winter price differentials, and might reflect behaviours adopted in the previous summer being continued into winter. There was also an overall conservation effect of 0.7% in winter. SCE recruited a sample of homeowners with smart thermostats into the study, and these households realized higher winter peak reductions of 4.9%. In general TOU rates did not affect satisfaction with utility prices compared to the control group.

2.2.2 Scandinavia

Although on a different continent, and with some societal differences, in other ways Scandinavia represents a context quite similar to that of New Brunswick, in that it is winter peaking, with cold winters and a large fraction of electric heat.

Ericson [2006] describes an opt-in TOU experiment in Norway. Customers were assigned to a TOU only tariff (N=171) group, or to a group with a choice of a TOU tariff or spot prices with direct load control of their electric

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[13] In all cases the summer peak to off-peak price ratio was much higher, up to double.

water heater (N=134)[14]; a control group (N=754) did not volunteer for new rates. TOU commodity peak prices of 17.5 ¢/kWh applied 7 – 11 AM and 4 – 8 PM on non-holiday weekdays, and off-peak prices of 0.6 ¢/kWh[15] applied at all other times. Spot prices were determined hourly the day before they were applied; spot prices remained very stable during the experimental period at ~ 4.8 – 5.8 ¢/kWh. Water heaters were disconnected during the two most expensive spot prices in the morning and evening, but this was not perfectly aligned with the TOU schedule, meaning that re-connection and catch-up[16] could occur during TOU peak hours. Hourly data were collected during Nov, 2003 – Apr, 2004. In the study period the mean outdoor temperature was 0.5 ºC (min -16.3 ºC), and mean electricity use in the control group was 2.2 kWh/h. Results indicated a mean peak reduction of ~ 1.8% for the TOU only group and ~ 2.4% for the group with TOU/spot prices with direct load control.

Doorman & Ericson [2010] report on a study of households (N=443) in Norway in 2006 that opted-in to a demand charge based on the maximum consumption during 7 AM – 4 PM on weekdays in each of the winter months (Dec, Jan, Feb). Standard rate customers paid 5.8 ¢/kWh, whereas the demand charge customers paid 3.1 ¢/kWh plus $112/kW/yr[17]. In the entire year of 2006 the mean outdoor temperature was 8.2 ºC (min -11.8 ºC), and mean electricity use in the sample was 2.7 kWh/h, although this reached ~ 4 kWh/h during the coldest hours. A survey of a sample of participants showed that 77% used wood as a supplementary heat source to electricity. Participants did not receive any feedback on their usage, or reminders when the tariff was in effect, a decision made to lower program costs. The average peak use reduction was 5%.

Saele & Grande [2011] describe another Norwegian pilot study. Forty households with electric water heaters participated in the study for one year; in four households, electric boilers also provided space heating. A large majority of participants (N=37) adopted an electricity tariff that combined a fixed charge, the spot price, and a TOU component. The TOU supplement (11.9 ¢/kWh)[18] applied 8 - 10 AM and 5 – 7 PM on weekdays only; the spot price was generally quite stable, around 4.5 ¢/kWh in a sample week in February, 2007. Direct load control of water heaters was enacted during TOU peak hours. Peak period load reductions were reported for the morning period only, and were ~ 1 kWh/h for standard water heaters (and ~ 2.5 kWh/h for the four households with electric boilers). Customers had a positive view of the pilot, and indicated their primary motivation for participating was personal financial gain.

Bartusch et al. [2011] report on a pilot study of a demand-based tariff in central Sweden in 2006 – 2008. Although 500 households were recruited into the study, only 50 had adequate data for analysis. In addition to fixed charges, participants received a demand-based commodity charge; during peak hours, defined as 7 AM – 7 PM on weekdays, customers paid a rate based on their five highest kW meter readings during peak hours, electricity use at other times was free. Prices varied over the period of the study, but as a guide, by the end of the study the prevailing conventional rate for electricity (charged in all hours to non-participants) was 5.8 ¢/kWh, whereas the demand-based charge was 13.8 $/kW[19]. Unfortunately, experimental effects were reported in absolute terms, rather than being weather adjusted, and so should be considered indicative at best. In the two 12-month periods following the new tariff, total electricity use declined by 11.1% and 14.2%, compared to the year before introduction; reductions were strongly concentrated in the winter, where they were

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[14] Another group were exposed to market spot prices determined the day before, but this group was too small (N=7) for the results to be considered in this report.

[15] Based on exchange rates in 2004.

[16] More electricity is used for the water heater to re-attain the desired water temperature following a period of curtailment.

[17] Based on exchange rates in 2006.

[18] Based on exchange rates in 2007.

[19] Based on exchange rates at the end of 2008.

roughly evenly distributed between peak and off-peak periods; however, average outdoor winter temperatures were 3.9 ºC and 1.4 ºC higher in these two years. Customer bills were also reduced.

DONG summarizes a TOU pilot in Denmark, which lasted 12 months, beginning in April, 2014. Treatment (N=488, opt-out) and control group (N=467) customers were selected, these customers did not use electric heat[20], and no automatic control devices were deployed. The TOU prices applied on weekdays, and were divided into low (8 PM – 6 AM, 1.4 ¢/kWh), high (6 AM – 5 PM, 5.2 ¢/kWh) and peak (5 PM – 8 PM, 9.1 ¢/kWh) periods, and the treatment group were protected against bill increases; the control group experienced the standard fixed tariff of 4.2 ¢/kWh. The TOU group exhibited 2.0% lower electricity use during the peak period, and it appeared that this was shifted to the low-price period.

An analysis by Katz et al. [2016] showed that, in the Danish context, demand response from variable pricing renders wind power more valuable.

EURELECTRIC [2017] records that 340,000 customers in Finland were on a form of RTP with prices fixed a day ahead; for some customers, certain hours were price-optimized for heating, based on heating capacity and weather forecasts. NER [2017] estimates that the greatest potential for DR in the Scandinavian residential sector lies in electric space heating[21], and that rate structures should encourage the raising of thermostat setpoints during periods of low demand, and the lowering of setpoints during periods of peak demand, using the building fabric as a heat storage medium. This is the same mechanism employed in the New Brunswick smart thermostat pilots [Pardasani et al., 2016, 2018, 2019].

2.2.3 Europe (excluding Scandinavia)

Several time-varying price studies have been conducted elsewhere in Europe. The majority of these locations are still winter peaking, although the winters are milder, and electric heating is not as prevalent.

One of the most widely- and longest-deployed TVR programs is the tempo tariff in France [Giraud, 2004; Giraud & Greiveldinger, 1993]. Although tempo continues to this day, the summary in this report refers to the quantitative findings at the time of the above citations. In Giraud [2004], the tempo tariff divided the year into blue (lower demand), white (mid demand), and red (high demand) days; there were 300 blue days, 43 white days, and 22 red days. On blue days nighttime (8 hours) prices were 5.0 ¢/kWh, and daytime (16 hours) were 6.4 ¢/kWh; on white days nighttime (8 hours) prices were 10.9 ¢/kWh, and daytime (16 hours) were 13.0 ¢/kWh; on red days nighttime (6 hours) prices were 20.7 ¢/kWh, and daytime (18 hours) were 59.1 ¢/kWh[22]. An initial pilot was conducted with 800 customers in 1989 – 1992 [Giraud & Greiveldinger, 1993], with sub-metering for 70 customers; because the development of this tariff was driven by the increase of electric heating end uses in France, red days occurred only Nov 1st – March 31st. The day colour was decided the day before, and shown on an in-home display half-an-hour before implementation. Load control was available to ensure certain appliances would only operate during the cheaper price periods. Daily consumption was reduced by 15% on white days and 45% on red days, compared to blue days. At the coldest temperatures (-4 ºC), average demand was reduced by ~1 kW on white days and ~2 kW on red days, compared to blue days. A survey of pilot customers showed 84% to be quite or very satisfied with the tariff, and 59% thought they had made bill savings. After 1995 the opt-in program has been subscribed by hundreds of thousands of customers, with the primary motivation of reducing bills; customers reported challenges when there were consecutive red days.

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[20] Participants also had to have annual consumption 1000 – 8000 kWh; the report states that treatment customers were not representative of Denmark as a whole.

[21] Water heating was a distant second.

[22] Based on exchange rates in 2004.

Two studies from Italy provide useful information. Torriti [2012] reports results from 1446 customers who experienced a fixed rate July 1st, 2009 – June 30th, 2010, and mandatory TOU rates July 1st, 2010 – June 30th, 2011; relatively few of this sample employed electric heating. TOU peak rates (13.5 ¢/kWh) applied 8 AM – 7 PM on weekdays, and the off-peak rates (9.6 ¢/kWh) at all other times[23]. Weather correction for consumption was crude, however, the TOU tariffs were associated with higher total energy consumption (13.7%), but lower bills (2.2%). There was a substantial shift in the morning peak to an earlier time (from 8 AM to 6 AM), and the evening peak (6 – 8 PM) was shifted to both earlier and later times. Maggiore et al. [2013] analyzed the effect of the introduction of mandatory TOU pricing on 8,427 customers across Italy (average annual consumption 2,124 kWh). The study included data in three periods: flat rate (Jan – Jun, 2010), transitional TOU (Jan – Jun, 2011), and final TOU (Jan – Jun, 2012). The overall average shift of consumption from peak to off-peak hours from 2010 to 2012 in the months January – June was 0.85%, but the largest shift occurred in (presumably) the coldest month of January (2.94%).

Schleich & Klobasa [2013] report results from a TOU study in Germany. Households were randomly assigned to groups in a larger DR field trial. Of these a sub-set volunteered for a TOU experiment, the final sample included 85 in the treatment group and 1,453 control group households, annual electricity use of the control group was ~ 3,500 kWh. TOU rates applied on both weekdays and weekends, the peak rate (10 AM – 6 PM) was 36.5 ¢/kWh, and the off-peak rate was 20.7 ¢/kWh; the control group received standard fixed rates which varied by region, with the median ~ 30.5 ¢/kWh[24]. The study period was May – Oct, 2010. The TOU group did not have any automated control technology. TOU effects were the same on both weekdays and weekends, with peak demand reduced 6 – 7 %. There was no effect on off-peak periods, suggesting peak shaving rather than peak shifting, and thus an overall reduction in consumption.

Ireland conducted a randomized control trial and various pricing and information treatments were applied. Di Cosmo et al. [2014] report on the effects of TOU pricing. Data were collected over one year, following a six-month control period (July, 2009 – Dec, 2010, overall). TOU periods were peak: 5 – 7 PM on normal weekdays; day: 8 AM – 5 PM on weekdays, and 5 – 7 PM on weekends and holidays; and night: 11 PM – 8 AM on all days. There was also a weekend rate, where the night rate applied all weekend. Before the introduction of TOU all participants paid 21.7 ¢/kWh at all times, and after TOU the control group paid 21.3 ¢/kWh. Several different TOU tariffs were deployed, the peak rate varied from 30.3 – 57.5 ¢/kWh, the day rate from 18.9 – 21.2 ¢/kWh, and the night rate from 13.6 – 18.2 ¢/kWh[25]. The TOU treatment groups also received one of four different forms of energy use feedback. In total there were 2,063 TOU participants across the various groups, and 768 in the control group. Winter temperatures during the study period were unusually cold for Ireland, with average monthly temperature during winter ~ 2 °C. Quoting an earlier analysis with the same data, TOU pricing was associated with a reduction of electricity use in peak periods of 8.8 % overall, with little effect in other periods, suggesting a conservation effect overall, this analysis is also replicated in Carroll et al. [2014]. Contrary to general trends elsewhere, substantially increasing the ratios of peak-to-off-peak prices had only a small effect on savings. The TOU reduction effect was significantly higher for the sub-set of houses with electric heating. Carroll et al. [2014] also found that participation in a treatment group was associated with an increase in knowledge of energy efficiency options, as expressed via survey responses.

Venizelou et al. [2018] report on a TOU pilot in Cyprus, results are provided separately for the winter period, on which we will focus, although clearly winters in this location are very mild. In the study, 300 consumers switched from a flat rate to TOU for the 2016 year, with reference data collected for 2015. Winter TOU periods and tariffs were peak: 4 – 10 PM (27.7 ¢/kWh); shoulder 6 AM – 4 PM and 10 PM – midnight (21.8 ¢/kWh); off-

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[23] Based on exchange rates in 2010.
[24] Based on exchange rates in 2010.
[25] Based on exchange rates in 2010.

peak midnight – 6 AM (16.0 ¢/kWh)[26]. The TOU participants received a “shadow bill” based on the flat rate to ensure bill protection. Evening winter peak demand was ~ 1.3 kW. Consumption during winter peak periods was reduced by 1.4% following TOU introduction.

2.2.4 Australasia

Thorses et al. [2012] describe a one-year (Aug, 2008 – July, 2009) TOU experiment conducted in Auckland, New Zealand. Although winters were mild, most residential heating was electric. Participants were randomly assigned to one of four groups, an information only group, and three groups that also received basic feedback and information on energy efficiency, and a time-differentiated electricity price. Prior to the start of the study there was some variation (17 – 21 ¢/kWh), so the pricing groups were expressed relative to the prior rate. For the low price differential group the peak and off-peak prices were the prevailing fixed rate plus or minus 2 ¢/kWh respectively, for the medium price differential group it was plus or minus 5 ¢/kWh, and for the high price differential group it was plus or minus 10 ¢/kWh. The peak period was 7 AM – 7 PM on all normal weekdays, and off-peak at all other times. A total of 332 households were in one of the four experimental groups, and there were 55 control group households. The only response to TOU prices came in winter, where participant households reduced electricity consumption by at least 10%, a shift of electricity use from peak to off-peak periods was also observed. Contrary to general trends elsewhere, increasing the ratios of peak-to-off-peak prices had no effect on savings, suggesting the effect was driven more by information and participation than the prices themselves.

A large smart grid initiative (2009 – 2013) in Australia also included a time-varying component [NLA, 2016]. Options available to customers included PriceSmart, which was a version of CPP, and SeasonSmart, a version of TOU. The standard fixed rate was 26.84 ¢/kWh, and the standard year-round TOU rates were peak: 2 – 8 PM (52.6 ¢/kWh); shoulder 7 AM – 2 PM and 8 – 10 PM (21.3 ¢/kWh); off-peak 10 PM – 7 AM (13.1 ¢/kWh). Under PriceSmart, the off-peak rate remained the same, and hours 7 AM – 10 PM were charged at 24.5 ¢/kWh; however, some hours in the 2 – 8 PM window on some days could be charged at a critical peak rate of 330 ¢/kWh. The study design called for events to be triggered when the forecast temperature was < 16 °C or 32 – 37 °C, however, there were few such days during the study that met these criteria, and other criteria were used; in actuality all events occurred in the summer (2013). Critical peak events could last 1 – 4 hours, and were called only nine times during the pilot study; participants were notified one day ahead. A total of 1,823 customers opted in to this program, and reduced their consumption by an average of 37 % during critical peak events, and by 0 – 4 % annually. Participation was driven primarily by a desire to reduce electricity bills. Under SeasonSmart, in Summer and Winter the off-peak and shoulder rates remained the same and standard TOU rates, but the peak rate was elevated to 74.5 ¢/kWh. This was compensated in Spring and Autumn by the elimination of the peak period, where hours 2 – 8 PM were also charged at the shoulder rate. A total of 567 customers opted in to this program, and reduced their consumption by an average of 9 % during peak periods in winter[27]; customers who also had feedback technology exhibited an overall conservation effect of 6%. Again, participation was driven primarily by a desire to reduce electricity bills. In further analysis drawn from the same dataset Motlagh et al. [2015] state that more than half of participants in the tariff experiments self-reported changing the times at which they used major appliances.

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[26] Based on exchange rates in 2016

[27] And by 4% in summer.

3 Conclusions & Discussion

The cited studies were conducted in a variety of locations with more or less relevance to New Brunswick, using different TVR designs, and widely different electricity prices; in many jurisdictions the base price for electricity was much higher than current rates in New Brunswick. Nevertheless, some general themes emerge:

- Utilities typically design TVR to be revenue neutral, that is the average customer, if they do not change their behaviour, will not receive a higher total electricity bill under TVR compared to the standard fixed rate. Of course, some customers may get higher bills due to their particular use profiles, and might have constraints that prevent behaviour change towards lower bills, in these cases, and when TVR is applied in a pilot project, utilities typically offer some form of bill protection. This bill protection could take the form of an up-front compensatory payment, a post-study rebate, or a "shadow bill" where the customer continues to pay according to the prevailing fixed rate, while receiving a bill showing what the cost would have been under TVR.
- Low-income customers may need specific consideration, as any risk of a bill increase represents a greater fraction of their available income and, further, they may lack the resources to invest in measures to lower consumption during peak periods [Baatz, 2017].
- TVR almost always resulted in a measurable reduction in average peak period usage, although the reduction was sometimes only a few percent. There was also sometimes a small overall conservation effect, although occasionally overall use goes up even as peak use declines.
- Higher ratios between peak and off-peak prices are often associated with higher peak use reductions, though this effect is not as clear for winter studies as for summer studies [Faruqui et al., 2017].
- Commercial deployments of TVR (i.e. beyond pilot studies) are usually offered on an opt-in basis, although Ontario is a clear exception where TOU pricing was compulsory for all (millions of) residential customers.
- The primary motivation for customers to opt-in to TVR studies or programs was the desire to save money, environmental considerations were typically a distant second.

In addition to these themes derived directly from the cited studies, several other publications suggest strategies to make TVR programs (and other demand response (DR) approaches to peak load reduction) more likely to succeed. Darby & McKenna [2012] examined DR specifically in cool climates, and concluded that successful DR requires simple tariffs, enabling technology, education, and feedback. Simple tariffs make it easier for homeowners to remember when peak periods apply and thus shift elective electricity use. Technology to show the instantaneous price or price band is also helpful [Svahnström, 2013; Allcott, 2011[28]], and studies in Scandinavia have also explored signalling the availability of renewable electricity as well as price as an effective way to change behaviour [Svahnström, 2013]. Enabling technology can "solve" at least part of the remembering challenge by allowing major appliances to be pre-programmed to automatically curtail use at specific times of the day or when prices reach a certain level. Education helps participants understand what the DR program is trying to achieve, why it is important, and what the participant can do to reduce their electricity use during peak periods. Finally, feedback shows the participant how much electricity they are using (in some cases compared to their peers) and what effect their behaviour change is having. These features of successful programs are echoed by EURELECTRIC [2017]. Lewis et al. [2012] expands on these themes at length, and with multiple examples from utility pilot programs form around the world.

Stromback et al. [2011] conducted a large review of feedback and TVR studies with the purpose of informing European decision makers. They made some additional suggestions for successful programs, including

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[28] A subset of participants received a "Pricelight" a plastic globe which changed colour from blue to red to indicate the current electricity price.

customer segmentation, with invitations to opt-in to pilots and programs tailored to the specific customer segments with certain characteristics. A segmentation approach can also help pilot design to maximize the fraction of participants, or potential participants, who will benefit. They also found that more frequent interaction (e.g. interviews, meetings, questionnaires) with participants improved results, although they recognized that while this might be effective for pilots, it is likely impractical for full roll-outs[29].

Faruqui & George [2003] provide some lessons learned from a commercial TOU rate deployed in the Seattle area. In this case the peak to off-peak price ratio was low (15% above and below the prior fixed rate), reflecting the large fraction of hydro power in that region. Initially, 300,000 customers were placed on the rate by the utility, and customer satisfaction was high, 55% of customers experienced bill savings, only 0.5% of participants opted out in the first year; peak period use reduction was estimated at 5%. Around a year later the program was restructured as opt-in, the peak to off-peak ratio was reduced, and a monthly charge of $1 was applied to TOU customers. With these changes it was estimated that 94% of customers would now pay more under TOU, and there was a 10% opt out rate. Many customers believed they had made behavioural changes to shift load and had not been rewarded. This created substantial negative media coverage, and consequently the TOU program was discontinued. The authors concluded that it is very important to manage customer expectations around bill savings, to communicate these expectations clearly, and to design the program such that a majority are likely to benefit.

The principles and considerations of rate design are outlined in some detail by NARUC [2016]. In the context of the Shediac project, they raise the possibility of different rates for customers with distributed energy resources (DER) to better recognize the multiple benefits that DERs offer to utilities, and to encourage their adoption.

Note that the TVR options explored in this report require the implementation of interval metering, which, in the contemporary global context would be achieved via the roll-out of AMI (smart meters). When and if AMI will be deployed in New Brunswick is not determined at the time of writing of this report. Seasonal pricing is a very limited version of TVR that may be implemented without AMI, and may simply be applied on top of the existing monthly meter reads. In the New Brunswick context, this would mean charging a higher price for electricity in winter (and a lower price in summer), compared to the current time-invariant rate, to reflect the higher demand, and higher cost of meeting this demand, in winter. In recent stakeholder consultations [Faruqui & Bourbonnais, 2019], a seasonal rate was proposed as an attractive, short-term, first step towards more complex TVRs; more complex TVRs would better align usage with the cost of production, but would also require AMI deployment. Although straightforward, this rate offers little potential to change user behaviour because shifting energy use between seasons is impractical.

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[29] Note that the potential for social media as an effective customer engagement tool has largely emerged only after the conclusion of many of the studies cited in this report.

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