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Preventing Electrical Shocks

What Ontario — And Other Provinces — Should Learn About Smart Metering

Ahmad Faruqui and
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In this issue...
Ontario has made a commitment to introducing smart electricity meters and dynamic pricing choices. That is commendable. The meters will help consumers to cut their electricity payments by using less power during peak demand periods. Less consumption at peak times will lessen the need for new generating capacity. However, achieving these results will depend on how the program is implemented.

The Study in Brief

Evidence from a major electricity pricing experiment in California strongly supports the Ontario government's decision to begin introducing smart meters and more economically rational pricing. It also identifies a number of pitfalls that all provincial governments should avoid if the financial benefits of meters and innovative pricing are to exceed the substantial investment and operating costs associated with them, as well as with the associated communications and billing systems and hardware.

Ontario, which was historically a winter peaking province, became a summer peaking province during the past five years, with increased use of air conditioners and slow growth of heating loads. Ontario's Conservation Task Force has estimated that demand-side measures can offset 1,350 megawatts of the significant growth in peak demand that is likely to occur over the next decade.

Dynamic pricing programs can make a contribution toward this goal. As shown by California's experience, it is feasible for customers to respond to price signals. For such programs to be cost-effective, though, the value of the reduction in peak load must be greater than the cost of smart meters. This is likely to require that governments introduce significant price increases, reflecting the marginal cost of both generation and transmission and distribution savings, on at least a few days of the peaking season.

Relatively modest price increases are unlikely to induce sufficient demand response to offset the costs of smart metering. Another key lesson worth noting from the California experience is that critical-peak pricing rates are likely to be more effective than traditional time-of-use rates.

Yet another insight is that, if asked to volunteer for a time-varying rate, the vast majority of consumers will refuse to do so. The major barrier is consumer inertia. Governments should not simply require that smart meters be installed and expect consumers to voluntarily sign up for time-varying rate options.

The central issue that the Ontario government must examine carefully is how to implement the rollout of smart meters in such a way that the costs do not exceed the benefits.

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Ontario experienced a power crisis in the summer of 2003, when the demand for electricity exceeded available in-province capacity at peak times, necessitating expensive power imports (Trebilcock and Hrab 2003). Above average temperatures led to increased air conditioning loads that raised peak demand. This happened at a time of dry weather conditions, which reduced hydroelectric capacity, further exacerbating the imbalance between demand and supply. Because electricity rates did not vary by time-of-day, customers had no financial incentives to reduce peak loads. Some load reduction probably did occur due to public appeals, but it is unclear whether it would have been sustained over time.

In the aftermath and following aborted market reforms, the government of Ontario has made a commitment to introducing smart meters and dynamic pricing choices in the province and it is developing policies to implement these options. This Commentary describes alternative pricing concepts, including time-of-use (TOU) and critical peak pricing (CPP), identifies other jurisdictions where such pricing designs were implemented, and reviews the results of a large-scale pricing experiment in California.

In Ontario, dynamic pricing of electricity is currently limited to the very largest industrial and commercial customers. Approximately 90 industrial customers directly connected to the transmission grid are billed on an hourly basis through interval meters, accounting for 15 percent of electricity demand. The Independent Energy Market Operator estimates that an additional 20 percent of electricity demand is attributable to industrial customers that have interval meters but are not directly connected to the transmission grid. These users responded to time-varying prices during the crisis of 2003. To further enhance demand response in the province and mitigate the adverse economic impact of future crises, it would be necessary to extend time-varying pricing to residential and small commercial and industrial customers.

In April 2004, while speaking to the Ontario legislature, Premier Dalton McGuinty signaled his government's intention to move in this direction by installing "a smart electricity meter in 800,000 Ontario homes by 2007… and in each and every Ontario home by 2010." These smart meters, "combined with more flexible pricing," would provide an economic incentive for customers to reduce energy consumption during the peak hours of the summer season, when the cost to generate electricity is much higher than at other times of the year. Smart meters have the capability of measuring customer usage in short time intervals of 15 minutes or an hour as opposed to standard TOU meters that can measure monthly consumption using only two or three time periods per day.

On July 16, 2004, the Minister of Energy asked the Ontario Energy Board (OEB) to develop an implementation plan to achieve these goals. Subsequently, the OEB issued a draft implementation plan for comment and discussion (OEB 2004). The draft plan states that large customers with peak demands greater than 200 kilowatts (kW) will be the first to get new meters, followed by industrial and commercial customers with peak demands between 50 and 200 kW and all new installations, including newly constructed homes. By 2010, all 4.3 million homes in the province will have a smart meter.

The OEB is also developing a regulated price plan that will feature prices that vary by time of use.[1] These prices were announced in March 2005 — but will only apply to customers with smart meters. They feature three pricing periods during weekdays with a ratio of 3:1 between the peak and off-peak periods. The prices were to stay in effect for one year and be reviewed every six months thereafter. The OEB expects that all utilities will be required to offer these prices to customers with smart meters by spring 2006.[2]

The government expects that the combination of smart meters and time-varying prices will provide customers with the necessary incentive to reduce peak loads. For example, they may choose to set the thermostat on the air conditioner higher by two-to-four degrees or by rescheduling some activities, such as dishwashing, to night-time hours. The government may also charge higher peak prices during critical days when the electricity system is running at capacity and when wholesale commodity prices are very high. Such conditions may be encountered on hot summer days when air conditioners are running flat out, or evenings during cold snaps when heaters, ovens, and lights are all being used.

The McGuinty government's resolve to implement economically rational pricing is a key element of its balanced approach to solving Ontario's energy problems and is worthy of emulation by other provincial governments in Canada. Studies conducted across a wide range of countries over the past three decades show conclusively that most consumers will reduce peak load in response to time-varying electricity prices. This is the case with large commercial and industrial customers, as well as small and medium commercial and industrial users, and even residential customers.[3]

Another benefit of implementing time-differentiated rates is the elimination of cross-subsidies among peak and non-peak electricity consumers. The extent of this cross-subsidy has been quantified in research carried out by our firm for Integral Energy and submitted to the Independent Pricing and Review Tribunal (IPART) of New South Wales, Australia. As a result of these subsidies, peak period prices are understated by a factor of four and off-peak prices are overstated by about 40 percent.[4] Users who consume most of their power during the off-peak periods are heavily subsidizing those who consume a large portion of their power during peak periods.

Thus, in addition to being economically inefficient, prices that do not vary by time period create a social equity problem. Such prices place a burden on lower-income groups, especially those without air conditioners or who do not directly make any significant contribution to the peak demand. This raises the average price of electricity for all customers and places pressure on governments (and regulators) to restrict these increases for the lower-income groups. A much better

1 See http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan.htm.

2 http://www.oeb.gov.on.ca/html/en/communications/fs_rpp.htm#11.

3 Mass-market time-varying programs are discussed in Faruqui and George (2002). Programs for large business customers involving hourly real-time pricing are discussed in Faruqui and Mauldin (2002).

4 See http://www.ipart.nsw.gov.au/submiss/ENR_DNSPs_03/Integral%20Energy%20-%20CRA%20Air%20Conditioning%20Impact%20Report.pdf.

approach would be to reform price structures by introducing time variation in prices.

In most countries and operating energy markets, residential and small and medium enterprises pay the same price during all hours of the year — highly averaged pricing that is often uniformly applied across locations, even though the costs to supply various areas can vary significantly. If prices were higher during the peak periods — in constrained locations — many consumers would find ways of reducing peak usage, lowering average power costs and unwinding cross subsidies. The construction of new power plants and transmission and distribution investments would be deferred, reducing the need for capital expenditure. The use of fossil fuels would be reduced and in all cases the environment would be improved.[5]

There are several ways in which to introduce time-varying pricing, including TOU pricing, CPP and real-time pricing (RTP). Because of their simplicity from a customer perspective and ease of administration for a utility, TOU and CPP rate options are likely to be more popular than RTP for the mass-market segment.[6] These options are discussed in the rest of this paper.

Time-of-Use Pricing

TOU rates feature two or more pricing periods in a day that are called peak and off-peak periods in a two-period configuration and peak, shoulder and off-peak periods in a three- or four-period configuration. Prices are fixed ahead of time for each of the periods and are highest in the peak and lowest in the off-peak. The rates are designed to be revenue neutral with respect to the standard rate; if average customers do not change load shape, they will not see a change in their electricity bills. In addition, the rates provide a strong incentive to lower the electricity bill by reducing peak loads and shifting them to the less expensive shoulder and off-peak periods.

Since the oil embargo of 1973, and more recently with the introduction of competitive markets, large power users in many countries have bought their power at a TOU rate. Even residential and small commercial customers are now being offered this option as a way of lowering their bills. Examples include the Salt River Project in Phoenix, Arizona, Pacific Gas and Electric Company in California, and Potomac Electric Power Company in Washington, D.C., and Maryland. Each of these utilities has several thousand residential customers on TOU rates.

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5 The concept of time-varying prices is well established. Moviegoers know that tickets cost less for matinee shows and air passengers know that nighttime flights are cheaper. Prices on the British Underground vary by time of day, as do bridge tolls and telephone rates in many countries. Balancing demand and supply becomes easier with peak load pricing for all capital-intensive industries. In the context of electricity, more than half a century ago, D. J. Bolton wrote, "One of the chief aims of a tariff, in so far as it directs consumption, is to encourage the use of electricity at such times as it is cheap to supply, and to discourage it at other times."

6 Chicago is conducting an experiment with residential customers in single family and multi-family dwellings. It has shown that customers are responding to RTP rates, saving money on their monthly bills and reducing utility peak loads. It holds promise that one day, RTP pricing may be widely implemented in the mass market.

Results from these utilities, as well as from experiments carried out by a variety of other utilities during the past three decades, provide strong evidence that residential customers do reduce peak loads in response to higher peak prices. In general, the price elasticity of demand for peak electric consumption falls in a fairly narrow range from -0.10 to -0.30. So, if the price during the peak period is doubled, one would expect demand to fall by about 10 percent-to-30 percent.

The most recent experience with TOU pricing in the United States took place in Washington state. Puget Sound Energy carried out the program as a large-scale pilot project that involved some 300,000 residential customers and 20,000 small commercial customers. The experiment featured a fairly mild TOU rate, with a peak-to-off-peak ratio of about 1.3:1. Even then, customers reduced peak usage by 5 percent month after month during the first year of the program.[7]

Utilities in Australia are introducing TOU options for three-phase supply on residential and small and medium commercial and industrial customers to damp peak loads caused by larger end-use appliances, such as central air conditioners and water heaters.

Perhaps the utility with the longest history of TOU pricing is Electricité de France (EDF), which introduced the practice to its residential customers on a voluntary basis in 1965. Currently, a third of the customer population receives electricity on a TOU rate. In 1993, EDF introduced a new rate design, *tempo*, which is a form of critical-peak pricing.

Critical-Peak Pricing

Customers on CPP rates are billed at time-of-use prices on most hours of the year and additionally face a much higher price during the year's most expensive 60-to-100 hours. EDF's *tempo* program has over 120,000 residential customers who face two daily pricing periods as they would on a traditional TOU rate, but the prices vary depending on the type of day. EDF divides the year into three types of days to reflect the imbalance between demand and supply in the power system. The days, named after the colours of the French flag, include blue days, which are the most numerous (300) and least expensive; white days are the next most numerous (43) and mid-range in price, and red days, which are the least numerous (22) and the most expensive. The ratio of prices between the most expensive time period (red peak hours) and the least expensive time period (blue off-peak hours) is about 15, reflecting the corresponding ratio in marginal costs. The days are called the previous evening and customers are notified through a variety of media.

Gulf Power, a utility in Florida, offers a similar type of rate to its very largest residential customers. It differs in two respects from the EDF rate. Gulf Power customers can be called the day of the event, and the length of the peak period on the critical days can also vary. The Florida utility has installed special equipment on customer premises that enables large appliances to respond automatically to the higher prices. Customers save about 15 percent on their power bills, even after

7 The experiment was terminated after 15 months because the lack of variation in the marginal cost of electricity between the peak and off-peak periods made the significant incremental cost of smart metering more than could be offset by the relatively modest benefits of the program.

paying a monthly rental of $5 for the additional equipment. (Unless otherwise indicated, all prices are in U.S. dollars.)

Another example of CPP rates is provided by Orion Energy New Zealand, a distributor that has implemented CPP for mass markets over the last decade. Orion Energy initially introduced the CPP rate along with its demand-side management programs designed to activate the market. Orion no longer runs the demand management programs, though the pricing alone has remained impressively effective in the market, delivering significant peak-demand reductions. As a result, Orion Energy has been able to eliminate all growth in its peak demand over the past nine years, despite strong economic growth.

Significant interest in the benefits of dynamic rates exists in California, a state that experienced a major electricity crisis in 2000/2001. California's policymakers concluded that the crisis, while caused by a myriad of factors, was exacerbated by the absence of "demand response" in the retail market (Jaccard 2002). Because retail customers did not see higher prices when supply was constrained relative to demand, they had no incentive to reduce power consumption.[8] Market simulations indicate that had RTP rates been in place for commercial and industrial customers in the summer of 2000, peak demand would have fallen by 2.5 percent, resulting in a drop in prices in the wholesale market of about 18 percent (Faruqui et al. 2001). In other words, time-varying prices would have helped mitigate the market power of generators.

As a result of the crisis, special legislation was passed allowing for the installation of interval meters on the largest 22,000 business customers whose loads exceeded 200 kW, at a cost of $34 million. Subsequently, the California Public Utilities Commission, the California Energy Commission and the California Power Agency initiated a joint agency proceeding on demand response, advanced metering and dynamic pricing. They created three working groups comprised of utility personnel, agency staff and other interested parties, including ratepayer advocates and vendors. One of these working groups was responsible for overall policy direction, another for developing ideas for residential and small commercial and industrial customers under 200 kW demand, and a third for customers above 200 kW demand.

One of the key topics that is currently under study is whether to install smart meters on residential and small commercial and industrial customers. As a first step toward making this decision, which may cost more than $2 billion, California's energy policymakers have implemented the largest pricing experiment ever conducted in the utility industry, involving some 2,500 residential and small commercial and industrial customers (Faruqui and George 2003a).

8 Gray Davis, the governor of California at the time of the crisis, was reluctant to change electricity prices, even though he conceded that would have solved the crisis in 20 minutes. Instead, the state resorted to spending millions of dollars on mass media advertising programs that encouraged customers to reduce consumption during peak hours and to reschedule their laundry activities. Such programs had a temporary effect on customer behavior that disappeared when the advertising programs ended.

California's Pricing Experiment

California's Statewide Pricing Pilot (SPP) is designed to test a variety of pricing options, including TOU rates and CPP rates. In California, standard residential tariffs involve an inverted-tier design in which the price of power rises with electricity usage. The typical residential customer pays an average price of about 13 cents per kW hour (kWh). Within the SPP, customers on TOU and CPP rates pay a higher price during the five-hour peak period that lasts from 2 p.m. to 7 p.m. on weekdays and a lower price during the off-peak period, which applies during all other hours.

Each TOU and CPP rate involves two sets of peak/off-peak prices, to allow for precise estimation of the elasticities of demand. On average, customers on TOU rates are given a discount of 23 percent during the off-peak hours and are charged a price of around 10 cents. They are charged 22 cents during the peak hours, which is 69 percent higher than their standard rate. Thus, with TOU rates, customers are given a strong incentive to curtail peak usage and to shift usage to off-peak periods. However, the incentive is much greater on selected days for customers on CPP rates, who are charged, on average, a price of 64 cents during the peak hours on 12 summer days, making prices nearly five times higher than the standard. On the peak hours of other days and the off-peak hours of all days they face prices that are slightly lower than the prices faced by TOU customers during these periods.

Analysis of data from the first summer of the California experiment indicates that CPP-rate customers face what are called rifle-shot price signals that can be very effective at reducing peak demand, thus damping wholesale prices and obviating the need for building costly power plants that would run for only a few hundred hours a year. Customers are likely to be responding to higher peak prices by reducing peak usage, such as cutting back on air conditioning, and perhaps by shifting some peak-period activities associated with laundry, dishwashing and cooking activities to lower-cost, off-peak periods. They may also be raising off-peak use in response to lower off-peak rates by increasing such functions as air conditioning and lighting levels. Because prices have changed in the peak and off-peak periods, the average price for electricity over the day may have changed for some customers, as well. This would trigger additional changes in usage.

Elasticities From the California Experiment

We evaluated the impact of the experimental prices to construct electricity demand models that could be used by utilities and regulatory agencies to estimate the impact of similar prices that were not explicitly tested during the experiment. To accomplish this objective, we estimated an econometric model called the constant elasticity of substitution (CES) demand model. The CES can be summarized by two elasticity measures, that of elasticity substitution (ES) and the daily price elasticity. The ES measures the change in the ratio of peak to off-peak electricity within a day that is induced by changes in the ratio of peak to off-peak prices. The daily price elasticity measures the change in daily usage that is induced by changes in the daily price, which varies across different day types.

We estimated the CES model using experimental data from the summers of 2003 and 2004 and the winter of 2003/2004. Statewide, the estimated average reduction in summer peak-period energy use on critical days was 13.1 percent. Impacts varied across climate zones, from a low of -7.6 percent in the relatively mild climate of zone 1 to a high of -15.8 percent in the hot climate of zone 4. The average impact on normal weekdays was -4.7 percent, with a range across climate zones from -2.2 percent to -6.5 percent.

The statewide impact estimate of -13.1 percent has a 95 percent confidence band of +/- 1 percentage point. This means that there is a 95 percent probability that the actual reduction in peak-period energy use on critical days based on average SPP prices would fall between 12.1 and 14.1 percent.

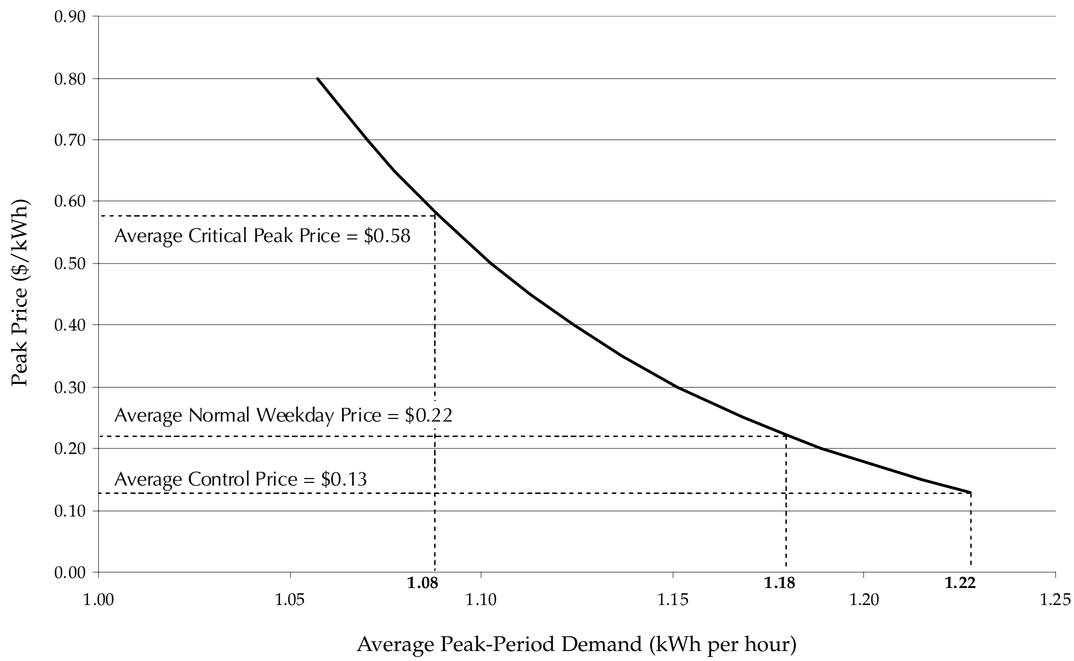
Other key findings for the CPP rate include:

- Differences in peak-period reductions on critical days across the two summers, 2003 and 2004, were not statistically significant;
- Differences in effects across critical days when two or three critical days are called in a row (as might occur during a heat wave) were not statistically significant;
- Average effects on critical days were greater during the hot summer months of July through September (the inner summer) than during the milder months of May, June and October (the outer summer);
- Households with central air conditioning were more price responsive and produced greater absolute and percentage reductions in peak-period energy use than did households without air conditioning;
- Demand response effects were lower in the winter than in the summer, and lower during the milder winter months of November, March and April (the outer winter) than during the colder months of December, January and February (the inner winter), and
- There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

The model specification indicates that price responsiveness varies with climate and with the saturation of central air conditioning (CAC). Based on average statewide weather conditions during the entire summer period and statewide CAC saturation estimates, the estimated ES has a value of -0.076. As a result, if the price ratio between peak and off-peak prices were raised by 100 percent, the corresponding ratio between peak and off-peak electric usage would fall by 7.6 percent.

For a customer with no CAC, the ES falls to a value of -0.045, while for a customer with CAC, it rises to -0.116. This analysis produced estimates that vary across four climate zones that differ with respect to average weather conditions and CAC saturations. In the mild climate of Zone 1 — which lies mostly along the northern coastline and includes the city of San Francisco — customers have an ES

Figure 1: *Peak-Period Demand Curve, California Average*



of -0.039, while in the hot climate of Zone 4 — which includes the deserts and outer areas of the Central Valley — customers have an ES of -0.113.

We have also estimated a daily price elasticity of -0.041 for the average customer in the state on a typical weather day. On that basis, if the daily price were to be raised by 100 percent, usage would drop by 4.1 percent. The daily price also varies with the presence or absence of CAC and with weather conditions. The low value is -0.031 and the high value is -0.051.

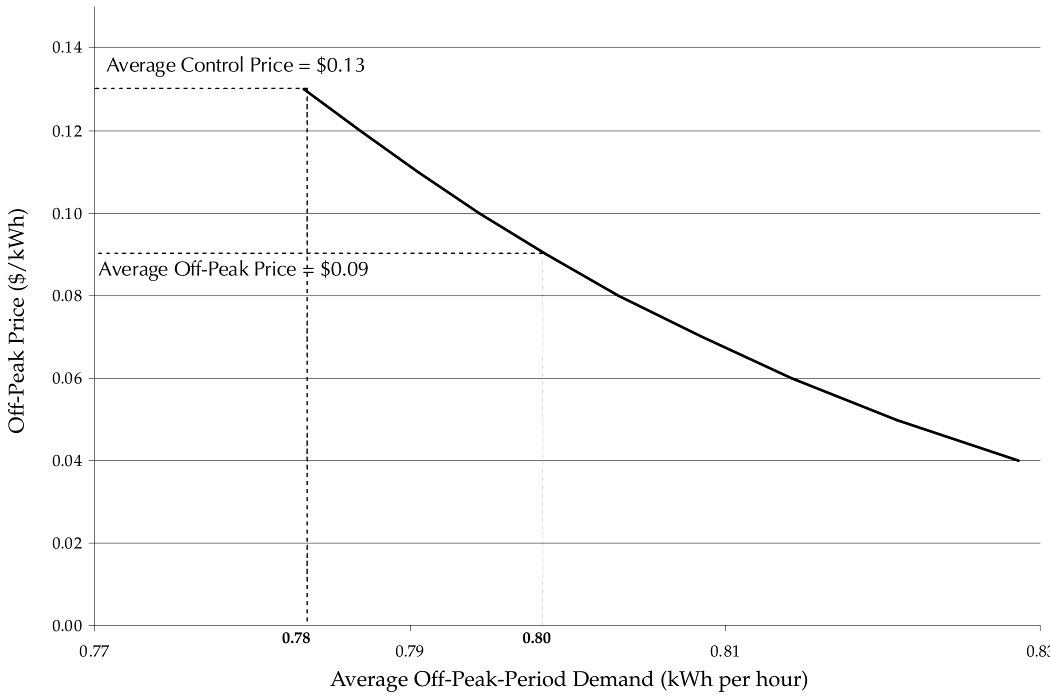
Using these elasticities, we can simulate the impact of rates other than those used in the SPP by plotting the demand curves for peak and off-peak usage associated with the CES model.

Demand Curves for Peak and Off-Peak Electricity Usage

The demand effects reported in the previous section are specific to the average prices that were used in the SPP. However, the impact of other prices for tariffs structurally similar to those tested in the SPP can be estimated using the underlying demand models. From these models, demand curves for peak and off-peak electricity use emerge. These curves are depicted in Figures 1 through 3.

The demand curve in Figure 1 shows how hourly energy use in the peak period varies with peak-period price, other things being equal. The curve shows the combined impact of the ES and the daily price elasticity of demand. A number of factors that are held constant along the demand curve, including weather, CAC saturation and off-peak price actually do change in the real world. Changes in any of these factors will induce shifts in the demand curve: For example, the curve will shift to the right as the weather heats up.

Figure 2: *Off-Peak Period Demand Curve, California Average*



The demand curve shows that at a price of 13 cents per kWh, which is the approximate price facing the control group and the price that the treatment customers faced in the pre-treatment period, hourly electricity use is 1.22 kWh during the peak period. At a TOU rate peak price of 22 cents per kWh, hourly demand falls to 1.18 kWh, yielding a price elasticity of peak energy consumption of -0.065. When the price further increases to a CPP price of 58 cents per kWh, hourly demand falls to 1.08 kWh, yielding a price elasticity of peak energy consumption of -0.096.

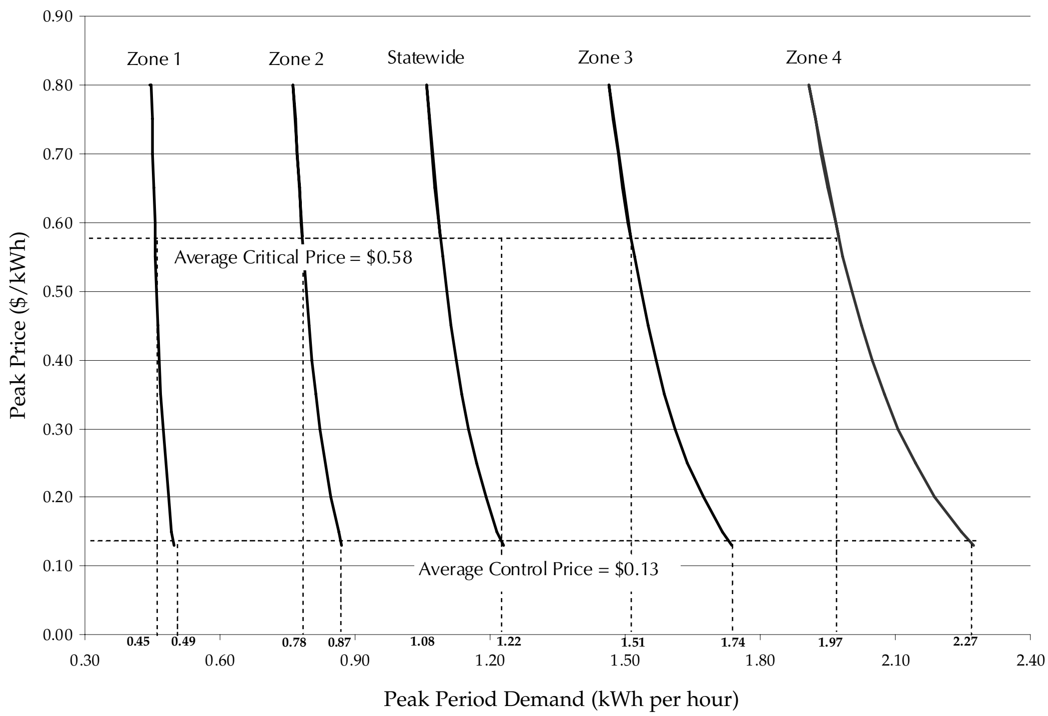
Figure 2 illustrates the demand curve for off-peak electricity use. It shows that a reduction in the price of off-peak electricity from the control group value of 13 cents per kWh to 9 cents per kWh increases hourly energy use from 0.78 kWh to 0.80 kWh, yielding a price elasticity of off-peak energy consumption of -0.050.

Similar demand curves can be constructed for peak and off-peak energy use in each of the four climate zones. The demand curves would be expected to vary across zones because weather conditions and the CAC saturations vary by zones.

Based on these values, the steepest demand curve (showing the least amount of price responsiveness, as evidenced by an ES of -0.039 and a daily price elasticity of -0.041) will be found in Zone 1, which is the coolest zone, and the flattest one (showing the highest amount of price responsiveness, as evidenced by an ES of -0.113 and a daily price elasticity of -0.032) in Zone 4, the hottest one.

Figure 3 displays demand curves for each of the four zones, and also repeats the statewide demand curve for comparison. It shows how much the quantity consumed in the peak period would change in each zone as the price of electricity moves from 13 cents per kWh to 35 cents per kWh. The biggest impact is observed in Zone 4 (-13.2 percent), followed by Zone 3 (-12.9 percent), Zone 2 (-9.03 percent)

Figure 3: *CPP Day Peak-Period Demand Curves by California Climate Zone*



and Zone 1 (-6.64 percent). The implied arc elasticities of demand are -0.112 in Zone 4, -0.109 in Zone 3, -0.079 in Zone 2, and -0.054 in Zone 1.

Implications for Canada

Before any results from California can be applied to Ontario, it is useful to review some basic data on the two regions to get some context. Table 1 provides data on population, peak demand and electricity consumption for the two regions.

While California is larger than Ontario in all three dimensions, Ontario is more electricity intensive. Table 2 provides information on average summer and winter temperatures in major cities of the two regions. During the peak summer months of July and August, average temperatures in Toronto are very similar to average temperatures in Concord, which lies at the boundary of Zones 2 and 3 in the pricing experiment discussed in the previous section. The California Independent System Operator regards Concord temperature conditions as the best single city representation of statewide peak loads. As a result, much of what has been found in California's experiment should be transferable to Ontario during the summer months. Of course, the significant divergence in winter weather between the two regions prevents much transferability of findings on customer price responsiveness in California's winter.

While evidence from California supports the Ontario government's interest in smart meters and more economically rational pricing, it also identifies a number of pitfalls that provincial governments throughout Canada should avoid if the benefits of smart meters and innovative pricing are to exceed the substantial

Table 1: *California and Ontario*

	California	Ontario
Population (million), 2004	35	12.5
Peak Load (MW), 2003[a]	54,000	24,000
Electric Energy, 2003 Consumption (TWh)	265	155

Source: California Department of Finance, California Energy Commission, and Ontario Independent Energy Market Operator.

[a] California peak demand and energy consumption data pertain to the entire state and not just to the customer of investor-owned utilities. The figures therefore differ from California Independent System Operator data.

Table 2: *Weather in Major Cities of California and Ontario Average Monthly Temperature*

	City	June	July	August	December	January	Feb
California	Bakersfield	78°F	83°F	82°F	47°F	48°F	53°F
	Concord	69°F	71°F	71°F	46°F	51°F	54°F
	Fresno	76°F	81°F	80°F	45°F	46°F	51°F
	Los Angeles	71°F	74°F	75°F	59°F	58°F	60°F
	Sacramento	74°F	77°F	77°F	48°F	48°F	54°F
	San Diego	67°F	71°F	73°F	58°F	58°F	59°F
	San Francisco	56°F	57°F	59°F	51°F	51°F	53°F
Ontario	Hamilton	64°F	69°F	68°F	26°F	21°F	22°F
	Ottawa	64°F	69°F	67°F	18°F	13°F	15°F
	Toronto	63°F	69°F	69°F	29°F	24°F	25°F

Source: www.weather.com

investment and operating costs associated with these meters and the relevant communications and billing systems and hardware.

Ontario, which was historically a winter peaking province, has become a summer peaking province during the past five years, with the increased penetration of air conditioners and stagnation in the growth of heating loads (IEMO 2004). Summer peaks occur late in the afternoon, between 3 p.m. and 5 p.m., in July and August. Under normal weather conditions, summer peak demand is forecast to be 24,160 (MW) in 2005 and to reach 26,160 MW by the year 2014, growing at an annual rate of 1.1 percent. Winter peak demand is expected to grow at an annual rate of 0.7 percent. If extreme weather conditions are encountered, the summer peak demand could rise to 30,000 MW by the year 2014. Ontario's Conservation Task Force has estimated that demand-side measures can offset 1,350 MW of this growth in peak demand (2004).

Dynamic pricing programs, such as CPP, can make a contribution toward this goal. As shown by California's experience, it is feasible for customers to respond to the price signal by modifying the temperature setting on their thermostats by a few degrees and rescheduling discretionary activities to off-peak periods. For such programs to be cost-effective, the value of the reduction in peak load must be greater than the cost of smart meters. This is likely to require that significant price increases, reflecting the marginal cost of both generation and transmission and distribution savings, be offered on at least a few days of the peaking season.

Relatively modest price increases are unlikely to induce sufficient demand response to offset the costs of smart metering. This fact was borne out by the experience of Puget Sound Energy in the Pacific Northwest, which indicated that a muted price signal offered neither sufficient opportunity for consumers to reduce energy bills nor sufficient reduction in peak demand to defer power plant construction as an offset to the metering investment (Faruqui and George 2003b). Another key lesson worth noting comes from California and indicates that CPP rates are likely to be more effective than traditional TOU rates.

Yet another insight from the California experiment is that, if asked to volunteer for a time-varying rate, the vast majority of consumers will refuse to do so. The major barrier is consumer inertia. However, inertia can be effective if consumers are placed on a time-varying rate by making it their default rate. They would be given the opportunity to choose a flat-rate option, which may reflect a hedging premium. In such a scenario, the vast majority will stay with the time-varying option. Governments should not simply require that smart meters be installed in homes and small businesses and expect consumers to voluntarily sign up for time-varying rate options in sufficient numbers to offset the cost of the meters. Governments will have to boldly change default prices to time-varying rates, while giving consumers the opportunity to opt out to a flat-rate option that fully reflects the cost of providing this option.

A third key issue that the Ontario government must examine carefully is how to implement the roll-out of smart meters in such a way that the investment and operating costs do not exceed the operational and demand response benefits that can come from the time-varying pricing options enabled by the meters. Our analyses for governments and utilities in Australia, New Zealand, Singapore, the United States and elsewhere indicate that if the metering cost per customer can be brought down to $150 or less, then the benefits of deploying smart meters on a mass scale have a reasonable chance of exceeding the costs.

In conclusion, we believe that there is substantial evidence from California and elsewhere that supports the application of time-varying pricing to encourage a conservation culture in Canada. However, such pricing options can only be offered in conjunction with smart meters. As with so many other complex investment decisions, the devil is in the details. There are many implementation pitfalls that could easily turn a good concept into a bad investment.

Careful analysis and planning of implementation options will be required before the bold vision of pricing electricity rationally can become a reality. If there is uncertainty about how customers are likely to respond to time-varying pricing options in any of Canada's provinces, it would be prudent to conduct a carefully designed pricing experiment to test the concept with a few hundred users before proceeding with full-scale implementation. Such an experiment should include multiple-rate types and multiple-rate levels within each rate type to enable estimation of the complete system of demand equations and associated price elasticities of demand.

The OEB's draft implementation plan encourages distributors to carry out pilot programs during 2005 to gain useful information about the installation and operation of smart meter systems. The OEB and the distributors should also use this opportunity to test likely customer response to time-varying prices, using approaches such as those described in this paper.[9]

9 For an evaluation of an early TOU pricing experiment involving small commercial and industrial customers in Ontario, see Ham et al. (1997).

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