PROPOSAL REGARDING TIME-SEASON RATEMAKING

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1 CONTEXT

1.1 Quebec Energy Strategy

In the 2006-2015 Quebec Energy Strategy,[1] the "*government wants Hydro-Quebec to progressively implement rates according to the season and hour of use among residential customers and to request approval from the Régie de l'énergie in 2007. The result of the proposed method must not be an increase in the overall bill of Hydro-Quebec consumers. Such a rate system, already in use elsewhere, would give the customers tools to better control their electricity bill. It would doubtless be an excellent way to reduce peak demand*."

1.2 Decision D-2007-12

In Decision D-2007-12, "*the Régie asks the Distributor to present a proposal in the next rate application to reform residential rates and explore options for seasonal and Time of Use rates*." Also, the Régie "*is interested by the possibility of dynamic rates which could be associated with the use of radio for meter reading*."[2]

1.3 Types of dynamic rates

Dynamic ratemaking implies a variation in energy prices as a function of different temporal periods (season, month, day, hour.) The price reflects the variability of supply costs, and in some network-specific cases, is a function of peak periods and off-peak periods, or, ultimately, hourly market price.

Two elements distinguish the main options for dynamic rates from each other: variability of prices and the variability of the periods during which the prices apply. As the next table shows, the more inflexible the parameters of the rate structure, the less the risk assumed by the customer.

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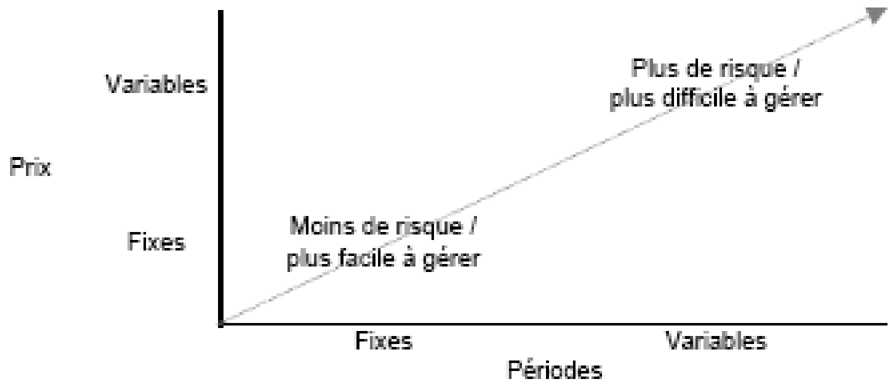
[1] See http://www.mrnf.gouv.qc.ca/publications/energie/strategie/strategie-energetique-2006-2015.pdf, page 57.

[2] http://www.regie-energie.qc.ca/audiences/decisions/D-2007-12.pdf, page 84

TABLE 1
RELATIONSHIP BETWEEN THE PARAMETERS OF RATES AND THE LEVEL OF RISK ASSUMED BY PARTICIPANTS



1.3.1 Time of Use rates

Time of Use rates imply different levels of predetermined prices based on defined consumption periods.

Simply, this could consist of:

- One price level for the week and another for the weekend;
- One price level for day and the another for night;
- One price level for summer and another for winter.

Because its prices are foreseeable, and the structure is easy to understand, Time of Use is the most commonly used among dynamic rates, especially among residential customers, and small consumers.

By way of illustration, Table 2 shows the panoply of TOU rates offered by Enel electricity company, a leader in the mass deployment of advanced meters. Nevertheless, applying a TOU rate does not necessarily require installation of complex advanced meters.[3] A double-register meter, with one register for the highest price and another for the lowest, can be sufficient to measure consumption.

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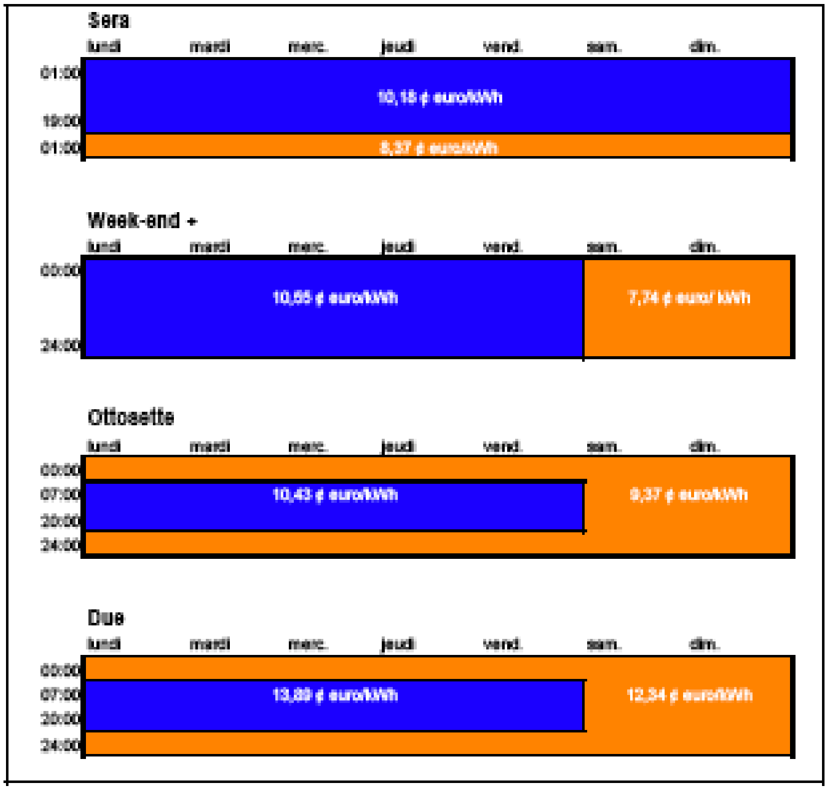
[3] See https://www.enel.it/sportello_online/elettricita/tariffeelettriche/.

TABLE 2: ENEL TIME OF USE RATES (MARCH 1, 2007)



1.3.1.1 Rate DH

The Distributor's rate options already include an experimental Time of Use rate, Rate DH (see Table 3). This rate is no longer open to new subscribers and has 159 customers

Rate DH arose from a pilot project launched in 1993 in the St-Jerome region during which 3.5% of customers contacted, (750 of 20,000 customers) agreed to try the program for a year. This participation rate is in the upper echelon of participation rates obtained by other North American companies for similar rates.

TABLE 3
DH RATE STRUCTURE

Fixed charge	40.64 ¢/day
Price of energy **Peak** During winter, from Monday to Friday, between 6 a.m. and 11 a.m. and 3 p.m. and 10 p.m. inclusive	14.64 ¢/kWh
Off-peak The rest of the time	4.13 ¢/kWh

During the winter of 1993-94, the 450 customers who participated in the pilot project permitted an average shaving of 0.83 kW per customer during the network's peak hours, for an overall impact of 0.66 kW per customer. By comparison, the anticipated shaving per customer due to dynamic ratemaking is only 0.07 kW in Ontario and 0.2 kW in California.[4]

Rate DH targets some 1,000 peak hours in winter (121 days*5/7 * 12 hours per day), meaning 1,000 high price hours during which customers try to reduce consumption, while the rest of the time, they benefit from a lower price than the regular rate. Even if Rate DH allowed shaving, precisely at each of the 300 peak hours, the fact remains that for the additional 700 hours, the shift does not meet the Distributor's requirements. Furthermore, up to 39% of the network's peak hours occur outside Rate DH's peak time frame. (See Table 4)

[4] See Smart meters: Monitoring report II presented in rate application R-3610-2006, http://www.regie-energie.qc.ca/audiences/3610-06/Requete3610/HQD-12-03.pdf

TABLE 4
COINCIDENCE OF DH RATE PEAK PRICE AND NETWORK PEAK

Year	Number of hours coincident with DH peak	Number of hours not coincident with DH peak	% of hours not coincident with DH peak
2003	215	85	28%
2004	182	118	39%
2005	220	80	27%

1.3.2 Real Time Pricing

When Real Time Pricing (RTP) is applied, the price level is generally established from hour to hour as a function of supply costs. Rates of this nature are generally offered to businesses to stimulate sales and obtain shaving during certain periods; they are rarely offered to residential customers.

RTP requires transmission of information to customers whether by Internet, phone, fax or advanced meter. In addition, consumption must be recorded with an interval meter.

1.3.3 Critical Peak Pricing

Critical peak pricing (CPP) is a rate concept intimately linked to the technology used in the communicating meter. This type of rate is a halfway point between Real Time Pricing and Time of Use Pricing; the goal is to apply the highest rates during the few hours annually when the network is at peak demand; this would be 1% of the hours in the year. While various types of CPP rates exist, this method is essentially a TOU rate applied most days of the year, coupled with an increased rate for critical days determined by the Distributor's needs. The number of critical hours is determined beforehand (100 hours annually, for example) while the number of incidents can be fixed or variable (theoretically, for the example of 100 hours, any combination between a single 100-hour event, and 100 1-hour events). The distributor may use available hours as a tool to manage peak time: it is only necessary to inform customers that the rate is changing to critical mode. The Tempo rate in use by France's EDF is a frequently used example of a CPP rate; this rate includes 6 prices, one for busy hours and one for slow hours for three types of days, from cheapest to most expensive, which EDF applies according to need. Nevertheless, despite its notoriety, Tempo is being phased out and has been closed to new subscribers since 2004.[5]

This type of dynamic rate typically requires information to be transmitted from the Distributor to the customer. Consumption must be measured with an interval meter.

1.3.3.1 Rate DT

Although Rate DT, designed for residential customers with a dual-energy heating system, is not a CPP rate in the strictest sense, it serves the same function. Effectively, as the structure of Rate DT indicates (see Table 5), customers are billed at a high price as soon as the temperature drops below -12 degrees Celsius.[6] Obviously, cold temperatures cause an increase in demand and in the occurrence of critical hours. The 119,000 customers at Rate D therefore permit a shaving of 790 MW during the winter peak, meaning more than 6 coincident KW on average per household.

TABLE 5
DT RATE STRUCTURE

Fixed charge	40.64 ¢/day
Price of energy during peak (<-12 C) Price energy during off-peak (>= -12 C)	17.55 ¢/kWh 4.08 ¢/kWh
Demand charge in winter for demand exceeding 50 kW	5.46$/kW

[5] http://entreprises.edf.fr/102151i/GrandesEntreprises/nosconseils/tarifsreglementesdelectricite.html

[6] The threshold is -15 degrees Celsius in some parts of Quebec.

2 INPUTS USED TO DEFINE A NEW RATE OPTION

2.1 Signal of Long-Term Marginal Supply costs

The structure of marginal costs is an important factor in the conception of a dynamic rate. The structure that will be used to conceptualize a dynamic rate is outlined in this application.[7]

2.1.1.1 Price Signal of Energy

The structure of the avoided cost of energy for the year 2007 and subsequent years reflects that of the reference market in which the Distributor currently purchases supply, meaning the difference between peak hours (6 a.m. to 10 p.m. on working days) and off-peak hours (all other hours) on the New York market on an annual basis.[8] The cost variance is established at 1.5 ¢ /kWh.

2.1.1.2 Price Signal of Power

The signal of avoided cost for the price of power is maintained at $10 /kW-year. This price reflects the cost of power acquired on short-term markets in 2007.

The additional cost of power ($10/kW-winter) is evenly distributed over the four winter months (December-March)

2.2 Rate Neutrality and Cross-Subsidization

A dynamic rate must be calibrated so that the targeted average customer who doesn't modify load profile pays the same amount as if he were at the regular rate; in this way, rate neutrality is ensured across the board.

In the current context of marginal cost structure, a shift in consumption patterns would have minimal impact on supply costs (1.5 ¢/kWh for a shift from peak to off-peak hours for the whole year and $10/kW for a transfer from peak to off-peak hours during the winter months.) In this scenario, the margin available to both reward customers who modify their load profiles and

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[7] See R-3644-2007.HQD-14, document 3.

[8] On an annual basis, peak hours represent 48% of total hours and off-peak hours represent 52%.

ensure that all residential customers benefit from the shift is far more limited. In this context, the reduction in supply costs should be completely transferred to participating customers:

- If a cost of 1.5 ¢ is avoided by transferring 1 kWh of peak-hour usage to off-peak usage, the savings would be wholly transferred to the customer.
- If a cost of $10 saved in winter by transferring 1 kW of peak-hour usage in winter to off-peak hours, the savings would be wholly transferred to the customer.

As a net result, every 1.5 ¢/kWh (or $10/kW) decrease in the revenue requirement would be compensated by a decrease of 1.5 ¢/kWh (or $10/kW) in anticipated revenue. In other words, residential customers as a whole would not benefit from cross-subsidization.

2.3 Universality

The two rate options currently offered to residential customers have prohibitive eligibility criteria. The customer on Rate DT must be admissible to Rates D and DM, and use, mainly for living purposes, a dual-energy system compliant with the Distributor's standards. Rate DH, however, is designed for customers who use electrical heating. This is why, amongst other requirements of the DH Rate pilot project, the customer's consumption during the winter periods in the 365 days preceding subscription to this rate must be 50% of his or her annual consumption, and be a minimum of 80 kWh/day.

The eligibility criteria are primarily designed to avoid free-ridership[9] and significant rate impacts. They also facilitate calibration by ensuring the homogeneity of targeted customers' profiles.

In this case, the Distributor notes that the government's directive regarding time-season ratemaking stipulates that it would "give the consumer the tools to better control his or her electricity bill." The Distributor takes from this stipulation that the opportunity to reduce the electricity bill should be offered to the maximum possible number of customers. In principle, the new option would be offered to all residential customers, excluding the some 4,500 customers who have capacity invoices (power demand exceeding 50/kW in winter), who have atypical load profiles.

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[9] Cases of free riders concern customers who benefit from a reduced bill without modifying their load profile or customers who increase their consumption in low price periods.

2.4 Voluntary Sign-Up

A dynamic rate must be offered on an optional basis in order not to penalize customers who would have difficulty modifying their energy consumption, for example, families with young children, sick people, seniors, and those who are always out of the house during off-peak hours. In other words, establishment of inequitable cross-subsidization between those than can modify their demand and those who cannot must be avoided.

For these reasons, dynamic rates are, as a general rule, offered to residential customers on an optional basis. Table 6 confirms this principle based on a survey of 65 major electricity companies: in more than 95% of cases, the customer voluntarily chooses the dynamic rate option[10]. In certain exceptional cases, a TOU rate is obligatory for major residential customers.

The Distributor notes, furthermore, that during the first technical meetings on rate structures, held in 2002 in the context of application R-3492-2002, stakeholders expressed from the beginning the wish that customers always retain the right to choose billing options.

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[10] Energy and Environmental Economics, Pricing and Demand Respond (DR) Programs, March 2006. See http://www.epa.gov/solar/pdf/surveyoftou_july06.pdf. Also see in Annex A the list of companies who participated in the survey.

TABLE 6
CHARACTERISTICS OFSIGN-UP FOR DYNAMIC RATES ACCORDING TO ENERGY AND ENVIRONMENTAL ECONOMICS

Characteristics of the rate	Number of cases	Percentage
Customers pay to sign up	50	88%
Voluntary sign-up only	54	95%
Voluntary sign-up for some customers	3	5%
At the customer's request (vs. by default)	56	98%
Regular rate (vs. pilot project)	52	91%

3 POSSIBLE SCENARIOS

3.1 Opening Rate DT to Customers without a Dual-Energy System

Rate DT, in which the structure of energy prices varies according to the temperature outside, efficiently meets the Distributor's needs because it targets a reduction in heating load during peak hours.

Rate DT is calibrated for neutrality for an average single-family home heated by electricity; this means that without a shaving in load, the electricity bill for this household remains the same as if it were at Rate D. Furthermore, if the heating load is reduced during peak hours because of a dual-energy system, the possible savings for participating households are in the range of $200 annually.

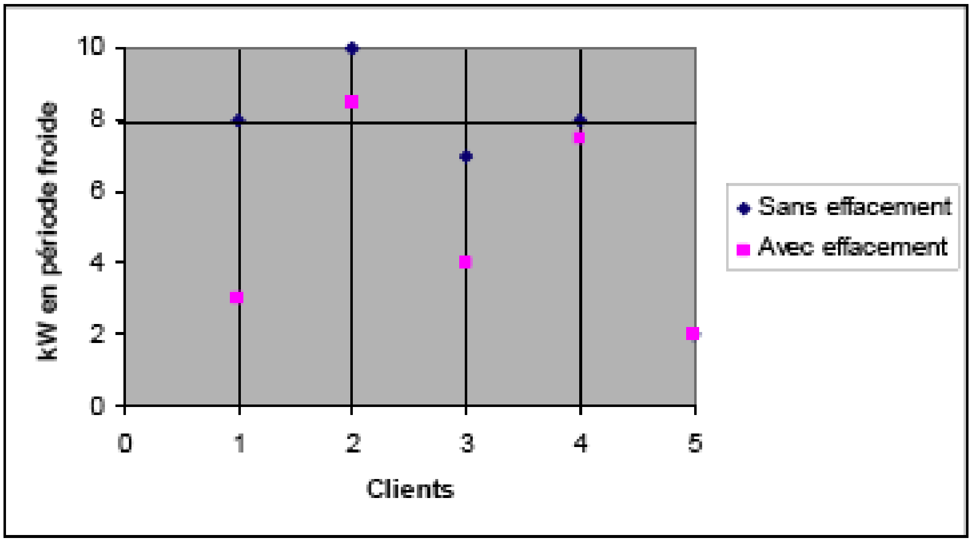
Opening Rate DT to all customers, whether they are AEH or not, with or without a back-up heating system, poses a problem in terms of rate neutrality for new subscribers. Basically, Rate DT is calibrated based on an average load profile that represents single-family homes with a dual-energy heating system. This is a fairly homogenous clientele in terms of annual consumption and the distribution of consumption over peak and off-peak hours.

Before shaving, the twin effects of low cost and number of kWh in off-peak hours offset the twinned effect of high cost and number of kWh during peak. In the same way, after shaving, the peak price and the number of shaved kWh create savings.

We conclude from this relationship that all customers whose profiles differ from the profile of an average Rate DT customer could become problematic. On one hand, it's possible that a customer, because of his consumption profile, might not only face greatly increased uncertainty of reducing his bill through a change in consumption habits, but might also risk significant losses. On the other hand, some customers could profit from Rate DT without providing the desired shaving. Neither of these cases is desirable. The following table illustrates five cases in point.

TABLE 7

ILLUSTRATION OF SHAVING DUE TO THE DT RATE FOR CUSTOMERS WITHOUT A DUAL-ENERGY SYSTEM



Customer 1 (on the abscissa) illustrates a typical customer of Rate DT, who in shifting from 8 kW to 3 kW during high price cold periods, shaves approximately 5 kW in peak hours. Certain customers (2,3,4), whether they use electricity for heating or not, could make certain efforts to reduce their peak consumption. However, their efforts are not sufficient to shave 5 kW and their peak consumption, at high price, remains significant. Because their consumption profile is very different from an average Rate DT customer, these customers will not be able to reduce their bill relative to Rate D.

Finally, Customer 5, with little effort, and little consumption at peak hours, could see his bill reduced relative to the Rate D.

During heavy cold periods, which can last from hours to days, it is difficult to shave significant load if one doesn't have a back-up heating system to offset the electricity heating. For example, EDF recommends residential customers using the TPC (Tempo rate) have a back-up heating system and an automated energy management system. Without this equipment, it is unlikely the customers could ever significantly reduce their load; in fact, they would surely lose money.

For these reasons, the Distributor does not see opening Rate DT to all residential customers as an appropriate response to the government's request.

3.2 Opening Rate DH

The current Rate DH was developed during the 1990s in a context of integrated business; its structure no longer reflects the price signal of current marginal costs. Furthermore, as Section 1.3.1.1 explains, customers' load shifts risk being frequently useless given that a third of the network's peak hours occur outside the peak time frame of Rate DH. Furthermore, Rate DH was calibrated for customers who heat with electricity. The problem of calibration, mentioned earlier with respect to the possible opening of Rate DT, arises again.

For these reasons, the Distributor does not see opening Rate DH to all residential customers as an appropriate response to the government's request.

3.3 New Pricing Option

Instead of opening admissibility to Rate DT and Rate DH to all customers, the Distributor proposes a CPP rate adapted to the actual context of supply, which would limit the risk of financial loss for the Distributor and for customers.

3.3.1 Calibration

Calibrating a rate means fixing the level of its components (fixed charge, cost of kWh, cost of KW) in order to meet predetermined objectives including that of rate neutrality.

To assure rate neutrality, it is only necessary to simulate, a priori, the bills for Rate D customers according to two rates: Rate D and the CPP rate. If the new rate is neutrally calibrated, the total revenues will be similar. This means that on average, without modifying the consumption profile, customers will get the same annual bill whether they are billed at Rate D or the CPP rate. Only in posteriori, by shifting their consumption from the high-price period to the low-price period, will they see savings on their bills.

Since all changes to rate structures generate their share of winners and losers, it is equally important to ensure the average impact is minimal relative to the annual bill for Rate D. For example, in the context of the *StateWide Pricing Pilot*[11], Californian authorities asked that the impact of new rate structures on customers' bills fall within an interval of +/- 5% relative to the base rate, before modification of load profile.

In the Distributor's specific situation, other constraints apply. For example, in the case of a straightforward time-season rate, the low price of the option should be superior to the low price of Rate DT (4.08 ¢/kWh) in order not to cannibalize the dual-energy residential market. The high price of the option should be superior to the 2nd consumption block under Rate D (7.03 ¢/kWh); this parameter is coherent with the Distributor's strategy of correcting the price signal of the 2nd block of energy under Rate D, which doesn't adequately reflect the price signal of marginal costs.

Another important consideration is to limit the impact of free-riders who would likely be the first to sign up for the new rate option:

> *"The customers that would sign up for a voluntary RTP program would be those that have a more attractive load profile – either flatter than most or actually*

[11] For more information on the StateWide Pricing Pilot, see "Smart Meters Monitoring report II" presented by the Distributor in application R-3610-2006.

peaking at times when system demand is low – or would have a more attractive profile once they responded to real-time prices."[12]

These customers, because they have specific load profiles, would see their electricity bill reduced without changing their behaviour or would increase consumption during low-price periods. The easiest way to avoid such cases of free-riding is to preserve the price signal in the base rate structure. In the case of the CPP rate, this must be calculated according to the Rate D structure, meaning the maintenance of a first daily block of 30kWh at an inferior price. This first daily block would be allocated according to the peak period and the off-peak period. According to the data drawn from the sample of customers analyzed by the Distributor, the annual consumption of customers is distributed evenly between peak and off-peak hours. On this basis, the first 15 kWh during peak and the first 15 off-peak kWh consumed daily would benefit from a lower rate.

Subsequently, the marginal cost structure is integrated, meaning the difference in peak and off-peak prices of 1.5 ¢/kWh on an annual basis. In the case of a straightforward time-season rate, this structure is sufficient to reflect the price differences.

The Distributor envisioned an artificial increase of the peak-off-peak difference. However, non-participating customers would have had to assume all remuneration greater than 1.5 ¢/kWh, with a billing impact contrary to the goals set out by the government; it is therefore not advantageous to give TOU rate participants remuneration exceeding the marginal cost signal . Furthermore, increasing this difference beyond 1.5 ¢/kWh would bring the off-peak price close to the low price of Rate DT, which could incite customers to switch from Rate DT to the TOU rate. Finally, the experience of Enel (see Table 2) demonstrates the viability of a TOU rate with a difference of 10% between peak and off-peak prices.

In the case of the CPP rate the Distributor envisions, the signal of a power supply cost of $10/kW in winter is also added. This rate would apply during the highest load hours of the network.

To establish the price during critical hours, one must divide the $10/kW by the number of hours considered critical and add this amount to the price of winter peak hours. This method is similar to that used by BC Hydro in the pilot project *Conservation Research Initiative Time of Use (CRI TOU) Program*[13] put in place in 2006.

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[12] The Hewlett Foundation, *Dynamic Pricing, Advanced Metering and Demand Response in Electricty Markets*, October 2002. http://www.ef.org/documents/DynamicPricingpdf

[13] BC Hydro, *Conservation Research Initiative Residential Time of Use Rate Application, August 2006*

> *"To obtain the prototype CRI TOU peak price, the $50/kW value was divided by the number of peak hours in the winter season (400) hours for the single evening peak case) which provides a value of 12.5 cents /kWh. This value was added to the of-peak price of 6.33 cents/kW and rounded up to provide an overall value of 19 cents/kWh."*

The Distributor proposes to retain 100 critical hours. In this way, the parameters of the CPP rate would be harmonized with those of the rates already offered by the Distributor (interruptible electricity options at Rates M and L, emergency generator use option.) With the consideration of 100 critical hours, 10 ¢/kWh would be added to the peak price in winter.

It would have been possible to reflect the cost of power in the price level of a simple TOU rate in winter. To do so, it would have been necessary to allocate the value of the power ($10/kW) to the 2800 winter hours (four months * 720 hours per month) or 0.36 ¢/kWh. In the Distributor's opinion, the resulting structure would have diluted the price signal relative to a CPP rate.

3.3.2 Customer Consultation

In January 2007, the Distributor asked an external firm to conduct a consultation of residential customers on dynamic rates. The consultation set out to evaluate:

- The appeal and understanding of such a rate for consumers;
- The profile of customers most interested;
- The reasons for lack of interest.

The consultant's report is available in Appendix B.

For the purposes of the consultation, the Distributor developed two theoretical rates: a TOU rate and a CPP rate. The CPP rate tested in the consultation, inspired by the Californian experiment, assumed 60 critical hours that could be applied any time during peak over the week, up to 16 hours per day.

Also, for the purposes of the consultation, the Distributor estimated the savings an average residential customer might see on his bill if he shifted certain uses (dishwasher, laundry, showers and baths) to off-peak periods all year. The savings on the bill could have reached, in this hypothetical context, $60 per year in the case of the TOU rate and about $70 annually for the CPP rate.

As a concept, the TOU rate, with peak and off-peak pricing, and offering potential savings, is interesting to consumers. However, the TOU rate tested interested only a small minority, and only a fraction of that minority would have signed up for the rate after reflection and calculation. A priori, although this is difficult to estimate, based on the interest and the intention of signing up, it is highly probable that less than one in 10 households would sign up for such a rate. Furthermore, free-riders, meaning customers who would benefit from the rate without making any effort, since they already consume during off-peak hours, as well as the small AEH customers that would be most inclined to subscribe to a TOU rate. Customers with environmental concerns would also be more interested by a TOU rate.

Generally speaking, the achievable savings on the bill do not seem sufficient in view of the effort involved in shifting uses. However, the Distributor cannot alter the structure of the TOU and the CCP rates to allow greater savings to participants without making the whole residential customer base bear “artificial” savings.

The time frame defined for the peak is also limiting for many customers. The time frame, however, reflects that used in the structure of marginal supply costs. All attempts to reduce the window, by offering an off-peak window over the course of the day or by moving the end of the peak period to 8 p.m. or 9 p.m. from 10 p.m. would devalue the actual price difference of 1.5 ¢ /kWh and, consequently, the benefit of shifting load to off-peak periods.

Finally, the CPP rate used for the purposes of the consultation assumed a price of about 25 ¢/kWh for 60 hours. The rate attracts certain customers because of the lower off-peak price compared to the preceding TOU rate and the slightly greater savings potential, but mainly, the majority of customers were worried about the peak period price of 25 ¢/kWh. This critical period, with an extremely high associated cost, frightened people.

As mentioned previously, the Distributor instead chose a scenario involving 100 critical hours, which has the effect of diminishing the cost per critical hour; the Distributor also took into account the constraints associated with potentially lengthy critical periods by planning for a non-critical window between 11 a.m. and 3 p.m.

3.3.3 Proposed Option

In view of the parameters and constraints outlined, the Distributor developed the following CPP rate, Rate DA, calibrated using the Rate D in effect on April 1, 2007.[14]

TABLE 8
PROPOSED CPP RATE (RATE DA)

	Winter		**Summer**		
	Peak	Off-peak	Peak	Off-peak	Rate D
1st block	6.01	3.33	6.01	4.51	5.29
2nd block	7.80	5.12	7.80	6.30	7.03
Critical Hrs.	17.80				

The terms associated with the critical hours under rate DA are similar to those associated with interruption under the interruptible electricity option for medium power customers. The 100 critical hours will be applied in blocks of 4 hours (25 blocks per year) and can be used during the week, excluding holidays. On the day before a critical period, customers will be notified before 3 p.m. The notice will be delivered via e-mail, a 1-800 line or by any other method established by the Distributor. The notice will indicate the number of blocks of critical hours occurring the next day, up to a maximum of two blocks, or 8 critical hours. These blocks could take place between 7 a.m. and 11 a.m. and 5 p.m. and 9 p.m.

In the summer, the structure of Rate DA translates the annual marginal costs structure on an hourly basis, meaning a difference of 1.5 ¢/kWh between peak and off-peak hours, regardless of the season.

In winter, however, consumption is priced at 17.80 ¢/kWh during the 100 critical hours, which is the price of the 2nd peak block in summer (7.8 ¢/kWh) plus 10 ¢/kWh ($10/kW divided by 100 hours.)

To ensure rate neutrality for customers who do not modify their load profile, off-peak consumption will be billed at a lower price, dropping from 4.51 ¢/kWh in summer for the 1st block to 3.33 ¢/kWh and from 6.30 ¢/kWh for the 2nd block to 5.12 ¢/kWh, for respective reductions of 26 and 19%.

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[14] The DA rate, as well as the DB rate, which will be addressed later, will be calibrated in function of the Regie's decision on this application.

The price reduction targets the consumption block with the least elastic demand in winter, which cancels out the effect of an increase in consumption during low pricing periods.

3.3.4 Evaluation of Savings on Bills of Participating Customers

The achievable savings under Rate DA are specific to each customer. They depend, among other factors, on the customer's annual consumption, load profile, ability to shift certain uses and the shift that will realistically be achieved. Consequently, it would be inappropriate to say that an average customer could see their bill drop by a specific amount by subscribing to Rate DA.

For this reason, the Distributor prefers to use multiple hypotheses by way of illustration to determine the magnitude of the possible savings. Hence, as Table 9 illustrates, by assuming shifts of 20 to 30% of the kWh usually consumed in peak hours to off-peak hours, customers could save about 3 to 4% of their annual bills. Details of the hypotheses and calculations are in Appendix C.

TABLE 9

ILLUSTRATION OF POSSIBLE ANNUAL SAVINGS

Annual consumption (kWh)	Total annual savings ($)		% of annual bill	
	Min.	Max.	Min.	Max.
10,000	25.0	32.5	3.6	4.6
15,000	32.5	43.8	3.1	4.2
20,000	40.0	65.0	2.9	4.6
25,000	47.5	86.3	2.7	4.9

The savings estimates in Appendix C assume, for the smallest customers, consumption shifts of 1000 to 3000 kWh throughout the year, as well as shifts of 1 to 2 kW during critical periods; for larger customers, the shifts in energy and power are respectively 3750 kWh and 3 kW. These shifts are realistic.

Table 10 presents the average consumption in energy and power of certain uses.[15] The possible shifts are numerous and depend on an infinite number of variables. However, it is possible to

[15] See http://www.hydroquebec.com/residentiel/mieuxconsommer/calcul_consom.html

define certain typical cases. For example, assuming that before the CPP rate, all these consumptions took place at peak:

- If an individual were to shift all his weekday showers to after 10 p.m., 624 kWh annually would be shifted (5 showers/days*52 weeks*2.4kWh)
- If a family were to use their dishwasher after 10 p.m., 3 times weekly, 505 kWh/year would be shifted (3 washes/week*52 weeks83.24/kWh)
- If a family were to transfer three loads of laundry to the weekends (warm water and dryer) 776 kWh/year are shifted (3 washes/week*52 weeks*2.59 kWh) and 3 dryer loads/week*52 weeks*2.39 kWh.)
- If a household were to use a microwave instead of a stove during peak hours, 4 kW would be shaved over a certain period of time.
- If a household were to use the vacuum cleaner on the weekend, 0.8 kW would be shaved over a certain period of time.
- If an individual were to shift use of her computer to off-peak, 0.3 kW would be shifted for several hours.

TABLE 10
CONSUMPTION OF CERTAIN USES AND POSSIBLE SHIFT

Consumption per unit (kWh)	
Bath	3.6
Shower	2.4
Washer	
Hot-water wash	5.64
Warm-water wash	2.59
Cold-water wash	0.24
Dishwasher	
Hot-air dry	3.55
Air dry	3.24
Dryer	
Normal cycle	2.39

Power demand (kW)	
Stove	5.0
Boiler	1.5
Micro-wave	1.2
Toaster	0.8
Vacuum cleaner	0.3
Colour television	0.3
Micro-computer	0.3

4 ECONOMIC EVALUATION OF THE NEW OPTION

The deployment of a new rate option involves significant costs, especially in terms of the meters. Consequently, the total cost will be a function of the meter technology employed and the participation rate of the customer base.

In order to ensure the optimization of deployment costs, the Distributor envisioned the use of several types of meters. Although each would be technologically acceptable, their cost, the type of billing associated with their use, and their characteristics yield different results. However, the Distributor emphasizes that the cost estimates presented are not the results of calls for tender to meter suppliers. They are drawn from experiences observed elsewhere and the best of the Distributor's knowledge. Although an analysis conducted from calls for tender would give different estimates, the Distributor submits that the approximate size of the investments involved and the general conclusions would not change much.

Finally, the offer of a CPP rate, as is the case with this type of rate option, targets load shift and not energy savings,[16] and the gains associated with the load shift are integrally transmitted to the participants.

4.1 Types of Meters Envisioned

The proposed Rate DA requires an interval meter that allows reading of hourly consumption. Many types of interval meters exist and cost varies considerably as a function of the type of communication link used; in the following sections, the Distributor presents three metering solutions using interval meters. Furthermore, in order to situate cost, the Distributor presents a deployment scenario for a simple Time of Use rate.

4.1.1 Double-Register Meters with Radiofrequency Reading

Multiple-register meters allow the measurement of kWh consumed during fixed time periods and are associated with a simple Time of Use option. These meters are equipped with clocks, and automatically shift from one register to the other at certain times. The data indicates the number of kWh consumed on each register. Because this requires the collection of only two or three measures per customer, the data can be read by mobile

[16] On this subject, see the monitoring report on advanced meters presented in application R-3579-2005 (HQD-13, document 2, pages 16 to 19)

radiofrequency. However, the clock requires regular maintenance, whether to replace the battery or to correct cases of clock drift.

4.1.2 Interval Meters with Integrated Load Profiles

For the purposes of the option proposed in Rate DA, it is possible to use non-communicant interval meters that register the hourly consumption of customers. The consumption cannot be read by radiofrequency because of the volume of data that must be collected. The hourly data are rather read by a meter reader with a scanner. The bill is calculated by establishing the correspondence between the hourly consumption data and the price in force (peak/off-peak/critical hours).

4.1.3 Interval Meters – Mesh Network and Power Line

The third and fourth options analyzed by the Distributor call for more advanced metering technology: price registers are triggered remotely, and the meters periodically transmit consumption data for each register.

The third metering option assumes two technologies according to population density. In a rural environment, data is transmitted via the power line, while in an urban environment, the metering is done through a mesh network of meters: a certain number of meters send information to a more advanced meter located in close proximity, which in turn relays the information to the Distributor.

The latter technology, if it covered the service area supplied by the Distributor, would require a minimal number of meters installed to create the mesh network. In view of the size of the service, a minimum of 400,000 meters would be necessary. Furthermore, the mesh network involves emerging technology that has not yet been tested through wide-scale deployment.

4.1.4 Interval Meter – Telephone Line

The fourth metering option involves interval meters with bi-directional communication capacity. However, communication would be done through a telephone line: the meter therefore must be equipped with an integrated modem. This type of link assumes that the measured data is stored in the meter, and collected regularly.

4.2 Participation Rate

4.2.1 External Experience

The consultation process conducted with the Distributor's residential customers as well as cases observed elsewhere indicate that few customers are inclined to subscribe to a dynamic rate; consequently, participation rates are extremely low.

> "*Gulf Power offers GoodCents Select residential CPP in Florida. Gulf Power and its parents, the Southern Company, are considered leaders among utilities in marketing and customer service. The community energy co-operative's Energy-Smart Pricing plan offers Illinois residences "real-time prices based on the hourly market rate. Both notify customers of high priced periods. The two retailers report that most customers who sign up save significant amounts of money, are satisfied and stay enrolled. But both programs get sign-up rates of only 1 per cent."*[17]

> *"A national EPRI[18] choice study found that under the most favorable conditions that about 20 % of residential customers would 'opt-in'[19] to a TOU program. The most favourable conditions assume customers are completely informed and encounter zero inertia and zero transaction costs to participate in the TOU program. If customers are not informed and there are costs to transact, then the participation level is expected to be about 5 %."*[20]

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[17] Letzler Robert, *Applying Psychology to Economic Policy Design: Ussing Incentive Preserving Rebates to Increase Acceptance of Critical Peak Electricity Pricing, University of California Energy Institute,* December, 2006, http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1065&context=ucei/csem

[18] Electrical Power Research Institute

[19] Opt in: sign up voluntarily. A contrario: opt out: cancel subscription in the option by default

[20] Tracey, Brian and Jonathan Wallach, *Peak-Shaving/Demand Reponse Analysis – Load-Shifting by Residential Customers, Resource Insight,* Inc. June 12, 2003, http://www.capelightcompact.org/pdfs/Peak%20Shaving%20Demand%20Response%20Analysis.pdf

> *"Participation in TOU rates and other types of residential DR*[21] *programs is generally low, usually ranging from almost zero to 3% of eligible customers."*[22]

> *"Allegheny Power's estimate assumed implementation of a smart thermostat and appliance control program at a cost of $12 million. The company's assumed participation rate was at about three percent of between 15,000 to 20,000 customers."*[23]

The low participation rates can be explained by the low foreseeable gains, themselves attributable to the price signal and energy volumes that can be shifted.[24] For customers to sign up for a dynamic rate, the difference between peak price/off-peak price as well as the volume of energy shifted must be significant. In the Distributor's current situation, the price signal doesn't offer a significant difference between peak periods and off-peak periods. Furthermore, the uses that can be shifted are few and do not represent significant volumes of energy.

Nevertheless, this situation is not specific to the Distributor. The situation is similar even where the cost structures are different.

> *"In the first 10 months of the program, residential customers in PGE's time-of-use program paid 24 cents more per month on average than they would have paid on Basic Service.*

> *Residential customers in PacifiCorp's time-of-use program paid 10 cents more per month on average than they would have paid on Basic Service."*[25]

> *"During the summer … the average residential TOU participant would realize power supply savings of 17 cents per month. During the winter … average power-supply savings would amount to only 2 cents per month."*[26]

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[21] Note: Demand response

[22] Gunn, Randy, *North American Utility demand respond survey,* Summit Blue Consulting, http://www.summitblue.com/publications/NAUtilityDemandResponse.pdf

[23] Pennsylvania Public Utility Commission, Demand Side Response Working Group, http://www.puc.state.pa.us/electric/pdf/DSR_Technology_Deployment_Rpt.pdf

[24] For more, see the report on the discussion groups in Annex 2.

[25] Oregon Public Utility, *Commission Demand Response Programs for Oregon Utilities,* May 2003, http://www.good¢.com/Info/DR%20Programs_Oregon.pdf

The amount of effort necessary to transfer uses from peak periods to off-peak periods also explains low participation rates.

Finally, without providing an exhaustive list of reasons for low participation rates, the risk that customers will see their electricity bills increase by switching to a dynamic rate is a major barrier to sign-up for such a rate.[27] This perception of risk is further amplified in the context of a CPP rate, which involves a very high price in critical periods. The customers are actually not wrong to be anxious: any change to the rate structure inevitably means winners and losers, even before modification of load profiles. Consequently, certain customers, in spite of efforts to transfer load to off-peak hours, could lose money.

> *"Many customers could "lose" on dynamic rates, with higher bills despite the same or even reduced demand levels. This preliminary bill analysis is troubling because most customers who alter their behavior will only see minimal bill savings – and many customers will actually see increased bills."*[28]

4.2.2 Hypothesis Retained by the Distributor

The participation rate obtained in the Distributor's DH rate pilot project was 3.5%.

Furthermore, although discussion groups are not the best tools to obtain quantitative data, the Distributor's consultation indicates that fewer than 1 in 10 customers would sign up for the proposed rate.

In view of these figures, and results observed elsewhere, a participation rate of 3% will be used in the analyses, representing 100,000 subscriptions in the Distributor's territory.

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[26] Tracey, Brian and Jonathan Wallach, *Peak-Shaving/Demand Reponse Analysis – Load-Shifting by Residential Customers, Resource Insight,* Inc. June 12, 2003, http://www.capelightcompact.org/pdfs/Peak%20Shaving%20Demand%20Response%20 Analysis.pdf

[27] On this subject, see the case of Puget Sound Energy, presented in the application R-3579-2005 in HQD-13, document 2.

[28] Southern California Edison, *Advanced Metering Infrastructure business case preliminary analysis, Volume 1,* before the California Public Utilities Commission, October 22, 2004

4.3 Evaluation of Costs

4.3.1 Cost of Metering and Reading

The four metering options analyzed assume that 100,000 customers will sign up for Rate DA over 3 years. The actual levelized cost in 2008 dollars takes into account the expenditures involved over a period of 15 years, particularly concerning costs for the use and reading of meters, where applicable.

- Double-register meters read by radiofrequency: on the basis of the per-unit cost of $200, the total levelized cost of measurement and reading of these meters (including the costs of development and installation) is $30 million. Over a period of 15 years, the annual operating cost associated is $18 million. These costs represent the periodic maintenance of the meter's internal clock and take into account a failure rate of 3%. The total levelized cost of measurement and reading of double-register meters with radiofrequency is approximately $48 million.

- Interval meters with integrated profiles: on the basis of a per-unit cost of $200, the total levelized cost of measurement and reading of these meters (including development and installation costs) is $30 million. Over a 15-year period, the annual operating cost associated with these meters is $22 million, including $19 million associated with the manual reading of the meters, which cannot be read by radiofrequency. The total levelized cost of measurement and reading of interval meters with integrated profiles is about $52 million.

- Communicating interval meters – mesh network and power line: on the basis of the per-unit cost of $150, the total levelized cost of measurement and reading of these meters is $151 million. This evaluation takes into account the fact that it would be necessary to install 400 000 meters in the Distributor's service area to structure the telecommunications network; this cost also includes the installation and upkeep of the injectors and collectors on the network. Over a 15-year period, the annual operating cost associated with these meters is $12 million. The total levelized cost of measurement and reading of communicating interval meters with a mesh network is about $163 million.

- Communicating interval meters – telephone line: on the basis of a per-unit cost of $445, the total cost of measurement and reading of the meters is $372, which includes the monthly telephone-line fee of $25 per meter over a 15-year period. In the same period, the annual operating cost associated with these meters is $6 million. The total levelized cost of measurement and reading of interval meters with telephone line is about $378 million.

4.3.2 Cost of the Customer Information System

The impact on billing costs varies considerably from one option to the next. Processing data from a double-register meter would involve only minor adjustments, because the CIS already does this type of processing for Rate DH. However, processing hourly data from the interval meters with integrated profiles would require the addition of the SAP EDM module, with an associated cost of $5 million.

4.3.3 Marketing and Customer Service costs

The marketing and customer service costs associated with a new CPP rate will be in the order of $7 million. This includes the sums required for:

- The establishment of a notification system to advise customers the day before a critical period.
- Communication activities targeting customers, including print advertising, production of promotional fliers, modification of the Distributor’s web site, promotional activities at trade fairs and
- Training and increase of workload in telephone service.

However, in the case of a simple TOU rate, the first item would not apply and the cost of marketing and customer service are lower.

4.3.4 Total Cost of the Options

Taking into account contingency costs associated with each metering option, the total deployment costs are presented in the following table.

TABLE 11

ESTIMATE OF THE TOTAL COST OF EMPLOYING A DYNAMIC RATE (100,000 CUSTOMERS)

	Cost in $million actualized in 2008
Double register meters	55
Interval meters with integrated load profiles	72
Interval meters with mesh network	235
Interval meters with telephone line	425

4.4 Analysis and Recommendation

The economic evaluation of the deployment of Rate DA rate highlights significant investments. The Distributor takes no position on how to recuperate the amounts in question. However, all the technological scenarios envisioned translate either into significant increases in the fixed charges of participating customers or into rate impacts on all residential customers, which is contrary to the directive of the government's energy strategy and the desired outcome of dynamic ratemaking.

TABLE 12

ESTIMATE OF THE ADDITIONAL FIXED CHARGE

	$/year
Double register meters	59
Interval meters with integrated load profiles	76
Interval meters with mesh network	249
Interval meters with telephone line	451

The economic evaluation of the deployment of Rate DA also highlights significant financial risks and unknowns that the Distributor wishes to control and clarify to the greatest extent possible before committing to the option.

The greatest risk is associated with the same calibration exercise that was realized on the basis of deduced consumption profile (peak-off-peak/critical hours) for 3 million residential customers. In this calibration, there are winners and losers, but on average, the impact is zero, and the foreseen revenues are the same as with Rate D.

Furthermore, the Distributor cannot assume without risk that the load profiles of those who sign up for the new option will be distributed in the same way as in the total customer base. Therefore, if only free-riders are interested in the option, the Distributor's revenues will decrease and there will be no increase in the cost of supply. Consequently, the drop in revenue will have to be compensated by a rate hike for non-participants, which would amplify the rate impact of the new option.

An additional financial risk exists for the non-participants, keeping in mind that the Distributor will pass on to participants the total avoided costs.

The participation rate also presents a substantial financial risk. Even though discussion group participants showed a certain reticence towards the CPP rate, the Distributor can only guess for the moment how the option would be received by the total customer base. A very favourable reception could have the effect of making deployment costs explode, particularly with respect to variable costs such as the price of meters. On the other hand, a cool reception would not necessarily mean a proportionate reduction in costs because the fixed costs will have been locked in (cost of telecommunications infrastructure, modifications to the billing system and marketing activities.)

For all these reasons, the Distributor believes it is prudent and justified to conduct a pilot project to allow a more accurate evaluation of the economic consequences of the introduction of Rate DA.

5 PARAMETERS OF THE PILOT PROJECT

5.1 Objectives

The Distributor proposes to conduct a pilot project to collect data to refine the economic evaluation of the options.

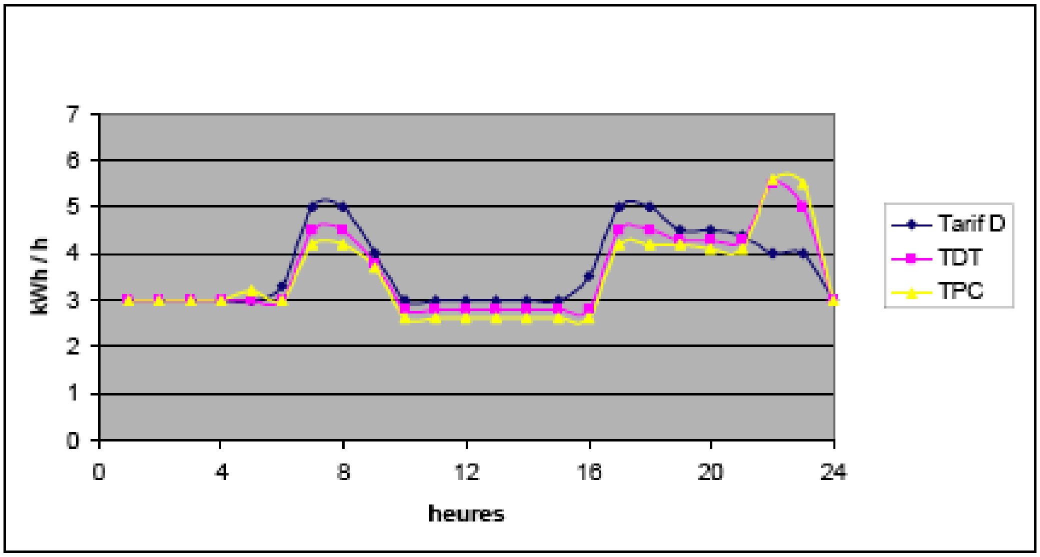
The main objective of the pilot project is to measure the load customers shift from peak hours to off-peak hours, as well as during critical hours. In this way, the Distributor hopes to validate the accuracy of the calibration of the proposed option and measure its contribution to reduction of peak demand.

A CPP rate is first and foremost a TOU rate to which is added a price for 100 critical hours. The customer who signs up for the CPP rate will shift part of his peak consumption to off-peak hours every day. During critical hours, the customer will shift an additional load. The total shift of this customer will in effect be the sum of the shift due to the TOU rate plus the load shift associated with the critical hours. Therefore, the total load shift cannot be solely imputed to the CPP rate. For this reason, the Distributor wishes to isolate these two effects by offering a TOU or a CPP rate to participants in the pilot project and measuring their load profile through interval meters.

The following table illustrates the type of information the Distributor wishes to gather through the pilot project. The graphic represents what could be the average load profile of a customer who signs up for the TOU or the CPP rate. These profiles are compared, for a day when critical hours are in force, to similar customers who subscribe to Rate D.

TABLE 13

ILLUSTRATION OF THE REDUCTION TO MEASURE WITH A PILOT PROJECT (HYPOTHETICAL SITUATION)



Furthermore, although these are secondary objectives, the Distributor wants to evaluate the effect of different variables on the reduction in peak period.

Since household electricity demand is linked to the temperature, the Distributor wants to evaluate the load shift according to various climate zones.

The Distributor also wants to verify whether the offer of coaching in energy efficiency can improve the effect of a dynamic rate. That means offering information on what can be done to reduce peak demand, on the accessories that can be used for certain uses (timers) or on the available options. The Distributor notes, however, that the marginal costs structure leaves little commercial room to manoeuvre; the coaching offer retained would have to reflect what would ultimately and concretely be offered in a mass deployment.

The Distributor also wants to study more profoundly the impact of the TOU rate for low-income households to which coaching in energy efficiency would also be offered.

Along the same line of thinking, although the Distributor does not envisage the use of such technology because of the prohibitive cost, the Distributor will use the pilot project as a window on the technology of interval meters in a mesh network. Because the meters are able to send signals, some customers would have access in real time to an indicator of critical hours. The Distributor will be able to verify whether the presence of such an indicator will have an impact on load-shifts.

5.2 Research Method

The research method of the pilot project envisaged by the Distributor is outlined in the following table. Although it is difficult to construct a method that would control all possible research biases, the proposed method meets all the rules of the art in the area.[29] This method is furthermore more ambitious and elaborate that most pilot projects in this area. It is comparable, however, to the *StateWide Pricing Pilot* in California. Appendix D includes, on this subject, the Ottawa Hydro pilot project, the description of a Hydro One pilot project, and the research method of the *StateWide Pricing Pilot*.

To evaluate the shaving of a participant in peak periods, it would be ideal to know the consumption profile this customer would have had in the same conditions under Rate D in order to compare it with the load profile with shaving.

The alternate solution proposed by the Distributor is to use a control group for each experimental group, meaning a group of Rate D customers that is as similar as possible to customers who would be interested in the dynamic rate. More precisely, as the research method outlined in Table 14 shows, each rate would be tested on at least 500 participants associated with 500 customers on Rate D.

TABLE 14
STUDY APPROACH

	Experimental	Control	Total
Zone 1 CPP rate – Temperature compared	350	250	*600*
Zone 2 CPP rate – Temperature compared	250	250	*500*
Zone 3 TOU rate	500	500	*1,000*
			2,100

The research method outlined in Table 16 can be expanded to take into account all the variables the Distributor wishes to study: the effect of coaching for energy efficiency, impact on low-income customers and impact of notification of critical periods. Table 15 outlines the proposed method in detail.

TABLE 15
PROPOSED STUDY APPROACH – DETAILED VERSION

[29] See http://www.energetics.com/madri/pdfs/Faruqui1-12-07.pdf

	Experimental Groups			**Control Groups**		
	CPP External notification only	CPP External notification and visual	TOU	CPP	TOU	*Total*
Zone 1 Advanced meters (bi-directional) INCLUDING	**250** *30 LI* *50 EE*	**100** *20LI*		**250** *50 LI*		***600***
Zone 2 Interval meters (manual reading) INCLUDING	**250** *50 LI*			**250** *50 LI*		***500***
Zone 3 Interval meters (manual reading) INCLUDING			**500** *100 LI* *50 EE*		**500** *100 LI*	***1,000***
Total	500	100	500	500	500	**2,100**
	600					

The table shows that:

- Each cell includes less than 20 % low income customers (LI);
- Support for energy efficiency (EE) is tested with 50 customers for each rate;
- The impact of notification for critical hours is tested on 100 customers.

5.2.1 Choice of Geographic Zones

The Distributor plans to recruit 3% of customers solicited for the pilot project. In view of this rate, and to obtain a number of participants ranging from 500 to 1,000 households, the targeted geographic zones should contain between 15,000 to 30,000 households, or have a population of 37,500 to 75,000, assuming an average of 2.5 residents per household.

However, excluding the cities of Quebec and Montreal, where it would be difficult to simulate a small-scale information and promotion campaign, municipalities with a sufficient population to serve as research venues are rare.[30] When the constraints of temperature and existence of low-income households are added, the pool of potential zones is reduced even further,

Furthermore, to ensure the quality of the data gathered, it would be inappropriate to test two types of rates in the same region, if only to guard against the risk of interaction between participants signed up for different rates, and consequently, confusion about the terms associated with either experimental group.

5.2.2 Recruitment

The participants will be recruited through solicitation by mail in three geographic zones. The customers will be informed of the launch of a dynamic ratemaking pilot project and invited to participate by returning the reply enveloped and completing a short questionnaire.

It is presumed that customers who agree to participate in a pilot project will be similar in terms of attitudes and consumption habits. Interested customers will therefore be randomly separated into two groups: an experimental group and a control group. The data from the questionnaires will ensure the representation of low-income customers.

5.2.3 Metering Option and Notification of Critical Hours

Advanced meters will be installed in the homes of participants in one of the zones where the CPP rate will be tested. This meter will change registers according to time slot and critical hours. It will also allow the installation of a critical hours notification device.

The other participants, whether they are offered a CPP rate (Rate DA) or a TOU rate (Rate DB) will have their meters replaced by an interval meter which will record hourly consumption. The text of rates DA and DB are appended in Appendix E.

If this were not a pilot project, the interval meter would not be required for the application of a TOU rate because a double-register meter would suffice. However, the interval meter is indispensable when it comes to comparing load profiles.

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[30] See the population of Quebec municipalities, http://www.stat.gouv.qc.ca/donstat/societe/demographie/dons_regnl/regional/mun_15000_2007.htm

5.2.4 Length of the Project

The pilot project will last for two years, from winter 2008 to spring 2010, which will cover two winter periods. In the Distributor's opinion, this length is justified a priori in order to validate the consistency of behaviours and the erosion of the customer base. Furthermore, two winters will cover a greater variation in climactic conditions.

5.2.5 Assessment of Impacts

The evaluation of the shaving at peak and critical hours will be achieved by comparing the average load profile expressed in KWh/h.[31] The analysis of the additional variables (effect of energy efficiency coaching, impact on low-income customers, impact of notification of critical hours) will be done on a similar basis.

5.3 Timeline

In order to be able to launch the pilot project in 2008, the Distributor has begun certain activities in terms of development of metering equipment (for example: ordering sample meters, programming, laboratory tests, development of software to process data on profiles and billing registers) and planning of marketing activities (production of surveys, letters of recruitment).

Nevertheless, the significant dates for the pilot project are as follows:

- Régie decision: February 2008
- Acquisition of meters/ adjustment of billing systems/training of representatives and preparation of informative material: April/June 2008
- Recruitment of customers (after the July 1 moving wave): July/August 2008.
- Information/alteration of meters: August/September 2008.
- Application of rate options: October 2008 to March 2010

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[31] A customer's load profile (in kW) is very volatile in the space of an hour; the power draws, whether they result from an action (turning on a light) or not (the water heater turns on) cannot be distinguished. Rather than attempt to compare the profiles of customers in terms of power and to deduce the shavings due to a dynamic rate, it is preferable to compare the volume of energy consumed per hour, meaning kWh/h.

- Interim report to the Régie and recommendation regarding launch of rate options: August 2009.

5.4 Cost of the Pilot Project

The cost of the project as presented in the previous pages is estimated at $5.8 million, including $5.3 million and a contingency fund of 10%. The cost breakdown appears in the following table.

TABLE 16
COST BREAKDOWN OF PROPOSED PILOT PROJECT

	M$
Metering	3.2
Customer Information Service Adjustment	0.2
Marketing and customer service	1.1
Market Research	0.8
Subtotal	*5.3*
Contingency (10%)	0.5
Total	5.8

The metering costs are justified mainly by the cost of development and installation associated with the purchase of new meters. In terms of telecommunication infrastructure necessary for advanced meters, the Distributor plans to rent communication systems and data collection systems for a small geographic zone. This solution is appropriate for a pilot project but would not be possible in the context of a mass deployment.

APPENDIX A
DYNAMIC RATE SURVEY:
COMPA NIES SURVEYED

Utility Name	Service Area	Ownership	Customers (2003)	Sales (MWh) (2003)	Web Site
AEP (Indiana Michigan)	Michigan	IOU	448,948	15,265,235	http://www.aep.com/
Alabama Power Co.	Alabama	IOU	1,363,120	52,208,020	http://www.southernco.com
Allegheny Power (West Penn)	Pennsylvania	IOU	693,432	18,991,265	http://www.alleghenypower.com
Ameren Union Electric	Missouri	IOU	1,170,848	31,901,036	http://www.ameren.com
Arizona Public Service	Arizona	IOU	931,642	24,562,305	http://www.aps.com/home
Baltimore Gas and Electricity	Maryland	IOU	1,174,814	31,114,062	http://www.bge.com
Bangor Hydro	Maine	IOU	110,000		http://www.bhe.com/
Boston Edison (NSTAR)	Massachusetts	IOU	687,315	11,678,710	http://www.nstaronline.com/
Carolina Power & Light Co (Progress Energy)	North Carolina	IOU	1,156,579	34,857,713	http://www.progressenergy.com
Cinergy(CG&E)	Ohio	IOU	641,688	16,796,420	http://www.cinergy.com/
Commonwealth Edison	Illinois	IOU	3,629,605	68,384,237	http://www.exeloncorp.comcom
Connecticut Light & Power CO	Connecticut	IOU	1,146,977	30,628,082	http://www.cl-p.com/
Consolidated Edison	New York	IOU	3,317,300	23,517,194	http://www.coned.com/
Consumers Energy Company	Michigan	IOU	1,741,397	34,238,970	http://www.consumersenergy.com
Detroit Edison	Michigan	IOU	2,134,371	43,671,787	http://dteenergy.com
Dominion Virginia	Virginia	IOU	2,094,286	68,323,177	http://www.dom.com
Duke Energy Corporation	North Carolina	IOU	1,664,280	53,024,862	http://www.dukepower.com

Utility Name	Service Area	Ownership	Customers (2003)	Sales (MWh) (2003)	Web Site
Duquesne Light	Pennsylvania	IOU	439,155	9,654,461	http://www.duquesnelight.com
El Paso Electric	Texas	IOU	244,876	5,042,868	http://www.epelectric.com
Florida Power and Light	Florida	IOU	4,17,229	99,339,144	http://www.flp.com
Florida Power Corp (Progress Energy)	Florida	IOU	1,510,494	37,956,702	http://www.progressenergy.com/
Georgia Power	Georgia	IOU	2,019,934	75,018,318	http://www.southernco.com
Gulf Power	Florida	IOU	389,807	10,884,789	http://www.southernco.com
Idaho Power	Idaho	IOU	408,829	12,351,079	http://www.idahopower.com
Indianapolis Power and Light Co (IPALCO)	Indiana	IOU	452,340	14,355,738	http://www.ipalco.com
Jacksonville Electric	Florida	Muni	378,500	12,293,323	http://www.jea.com
Jersey Central Power & Lt Co	New Jersey	IOU	987.636	18,786,247	http://www.firstenergycorp.com
Kansas City Power and Light (KCPL)	Missouri	IOU	265,829	8,256,870	http://www.kcpl.com
LADWP	California	Muni	1,535,271	23,040,163	http://www.ladwp.com
Long Island Power Authority	New York	Muni	1,082,903	18,834,909	http://www.lipower.org/
Massachusetts Electric Co (National Grid)	Massachusetts	IOU	1,189,951	17,212,298	http://www.nationalgridus.com/masselectric/
Niagara Mohawk (National Grid)	New York	IOU	1,500,299	20,934,910	http://www.nationalgridus/niagaramohawk/
Northern States Power (Xcel)	Minnesota	IOU	1,163,850	30,417,980	http://www.xcelenergy.com
Ohio Edison (First Energy)	Ohio	IOU	713,508	16,879,469	http://www.firstenergycorp.com

Utility Name	Service Area	Ownership	Customers (2003)	Sales (MWh) (2003)	Web Site
Pacific Power (PacifiCorp)	Oregon	IOU	514,403	13,227,334	http://www.pacificpower.net
PECO Energy (Exelon)	Pennsylvania	IOU	1,217,724	33,707,980	http://www.exeloncorp.com
PG&E	California	IOU	4,870,671	47,881,180	http://www.pge.com
Potomac Electric Power	Washington, D.C.	IOU	420,776	10,468,174	http://www.pepco.com
PPL Electric Utilities	Pennsylvania	IOU	1,313,084	33,635,019	http://www.pplelectric.com
Public Service Co of Colorado	Colorado	IOU	1,277,525	25,845,962	http://www.xcelenergy.com
Public Service Elec & Gas Co	New Jersey	IOU	2,033,550	38,766,006	http://pseg.com
Puget Sound Energy	Washington	Iou	968,586	19,591,637	http://www.pse.com
SCE	California	IOU	4,528,289	52,229,092	http://www.sce.com
SMUD	California	Muni	547,651	9,917,373	http://www.smud.org
TXU Electric Delivery	Texas	IOU	2,608,390	79,049,806	http://www.txuelectricdelivery.com
United Illuminating (UI)	Connecticut	IOU	320,993	5,763,052	http://www.uinet.com/
Wsiconsin Electric Power Co (WE Energies)	Wisconsin	IOU	1,033,818	24,858,918	http://www.we-energies.com
Wisconsin Public Service (WPS)	Wisconsin	IOU	401,701	10,388,244	http://www.wisconsinpublicservice.com

Utility Name	Service Area	Ownership	Web Site
ACEA-Electrabel	Italy	Private	http://www.aceaelectrabelelettricita.it
Bewag (Vattenfall)	Germany	Private	http://www.bewag.de
China Light and Power	Hong Kong	Private	http://www.clpgroup.com
Electrabel	Belgium	Private	http://www.electrabel.com
Electricidade de Portugal (EDP)	Portugal	Private	http://www.edp.pt
Electricite de France (EDF)	France	State	http://www.edf.fr
Enel SPA	Italy	Private	http://www.enel.it
EnviaM (RWE)	Germany	Private	http://www.enviam.de
Hyrdo One	Canada	State	http://www.hydroonenetworks.com
London Energy (EDF Energy)	UK	Private	http://www.london-energy.com
NUON	Holland	Private	http://www.nuon.nl
RAO-UES (United Energy System of Russia)	Russia	State	http://www.rao-ees.ru
Tokyo Electric Power Co (TEPCO)	Japan	Private	http://www.tepco.co.jp
Vattenfall	Sweden	Private	http://www.vatenfall.se

APPENDICES B, C AND D OMITTED

APPENDIX E
TEXT OF RATES DA AND DB

Section 7 below has been added to Chapter 2 of the text of the Distributor's Rates and Conditions, and comes into force on April 1, 2008.

Section 7

Rate DA

2.45. Parameters of Application: Rate DA is an experimental Time of Use rate. It applies to all Rate D subscriptions selected by the Distributor, providing that the customer accepts the invitation to subscribe within the established time limit.

Rate DA applies for a limited period, namely until March 31 2010 at the latest, or until the customer cancels the subscription.

2.46: Definition: In the following Section, terms shall be understood as follows:

"critical hours": All hours between 7 a.m. and 11 a.m. and 5 p.m. and 9 p.m. excluding

– Saturday and Sunday

– December 24, 25, 26 and 31, January 1 and 2, as well as Good Friday and Easter Monday, when these days fall in the winter period.

2.41 Metering: All electricity delivered must fall under a single subscription and be measured by a single meter that will permit distinct measurement of consumption during each of the periods outlined in this rate.

2.48 Structure of Rate DA: The structure of Rate DA is as follows:

40.64 ¢ daily fixed charge, plus

4.51 ¢ per kilowatthour for the first 15 kilowatthours of energy consumed in the summer period:
– between 10 p.m. and 6 a.m. from Monday to Friday,
– Saturday and Sunday;

6.30 ¢ per kilowatthour for the rest of the energy consumed in the summer period:
– between 10 p.m. and 6 a.m. from Monday to Friday,
– Saturday and Sunday;

3.33 ¢ per kilowatthour for the first 15 kilowatthours of energy consumed during the winter period:
– between 10 p.m. and 6 a.m. Monday to Friday,
– Saturday and Sunday,
– December 25 and January 1;

5.12 ¢ per kilowatthour for the rest of the energy consumed in the winter period:
– between 10 p.m. and 6 a.m. Monday to Friday,

– Saturday and Sunday,
– December 25 and January 1;

6.01 ¢ per kilowatthour for the first 15 kilowatthours of energy consumed:
– between 6 a.m. and 10 p.m. Monday to Friday;

7.80 ¢ per kilowatthour for the rest of the energy consumed:
– between 6 a.m. and 10 p.m. Monday to Friday;

17.80 ¢ per kilowatthour for energy consumed during critical hours.

2.49 Terms applicable to critical hours

Advance notification:	3 p.m. the day before
Minimum number of critical hours per day	4
Maximum number of critical hours per day	8
Maximum number of critical hours per year	100

2.50 Notification of critical hours: The notification of critical hours is sent to customers via e-mail or any other method arranged by the Distributor.

2.51 Start of application of Rate DA: Rate DA applies starting the date of installation of the appropriate metering equipment.

Section 8 below has been added to Chapter 2 of the text of the Distributor's Rates and Conditions, and comes into force on April 1, 2008.

Section 8

Rate DB

2.53. Parameters of Application: Rate DB is an experimental Time of Use rate. It applies to all rate D subscriptions selected by the Distributor, providing that the customer aceepts the invitation to subscribe within the established time limit.

The DB rate applies for a limited period, namely until March 31 2010 at the latest, or until the customer cancels the subscription.

2.41 Metering: All electricity delivered must fall under a single subscription and be measured by a single meter that will permit distinct measurement of consumption during each of the periods outlined in this rate.

2.48 Structure of Rate DB: The structure of Rate DB is as follows:

40.64 ¢ daily fixed charge, plus

4.51 ¢ per kilowatthour for the first 15 kilowatthours of energy consumed:
- between 10 p.m. and 6 a.m. from Monday to Friday,
- Saturday and Sunday,
- December 25 and January 1;

6.30 ¢ per kilowatthour for the rest of the energy consumed:
- between 10 p.m. and 6 a.m. from Monday to Friday,
- Saturday and Sunday;
- December 25 and January 1;

- December 25 and January 1;

6.01 ¢ per kilowatthour for the first 15 kilowatthours of energy consumed:
- between 6 a.m. and 10 p.m. Monday to Friday;

7.80 ¢ per kilowatthour for the rest of the energy consumed:
- between 6 a.m. and 10 p.m. Monday to Friday;

2.51 Start of application of Rate DB: Rate DB applies starting the date of installation of the appropriate metering equipment.