Designing Pareto-superior demand-response rate options

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Abstract

We explore three voluntary service options – real-time pricing, time-of-use pricing, and curtailable/interruptible service – that a local distribution company might offer its customers in order to encourage them to alter their electricity usage in response to changes in the electricity-spot-market price. These options are simple and practical, and make minimal information demands. We show that each of the options is Pareto superior \textit{ex ante}, in that it benefits both the participants and the company offering it, while not affecting the non-participants. The options are shown to be Pareto superior \textit{ex post} as well, except under certain exceptional circumstances.

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1. Introduction

Electricity deregulation has recently sparked substantial research that encompasses four principal lines of inquiry: market architecture, economic efficiency, trading efficiency, and the lack of retail-demand response to changes in wholesale electricity prices.

The primary focus of market architecture is the design of a market structure to replace one that is typically dominated by a monopolistic integrated utility [1-5]. This transition from a regulated market for electricity generation to one that is workably competitive has been difficult [6]. Experience from Alberta, California, the United Kingdom and Norway suggests that deregulated energy markets have failed to provide electricity consumers with reliable service at stable and reasonable rates [7].

Economic efficiency implies that the evolving deregulated wholesale markets are workably competitive and result in prices that approach short-run marginal generation costs. With California as the case in chief, this line of inquiry has generally concluded that wholesale electricity markets are typically oligopolistic, and that prices can substantially exceed their competitive levels [8-12]. Moreover, concentrated ownership of transmission rights and transmission congestion exacerbate local market power and further raise market prices above their competitive levels [13-14].

Trading efficiency implies that the deregulated wholesale markets do not offer arbitrage opportunities. Market power and trading efficiency are not incompatible, so long as traders cannot consistently earn arbitrage profit. Research into the trading-efficiency issue has generally found that to a large extent wholesale electricity trading is efficient [15-18], that electricity forward prices contain a risk premium [19-22], that electricity futures markets are also efficient
[23], and that gas and electricity spot markets are intertwined [17], as are their futures markets [24].

It is the fourth line of inquiry, however, that we pursue in this paper. Specifically, how can a post-reform local distribution company (LDC) avoid the adverse consequences of the insensitivity of electricity usage to wholesale-price variations that have no immediate impact on the retail customer? An important case in point is California’s frozen retail rates designed to collect stranded costs, which was a significant contributory factor to the California electricity crisis [7, 10, 25-29].

The lack of retail-demand response to spot-market price changes is prevalent and easily explained. An LDC typically owns a local distribution network, prudently buys wholesale electricity to meet its retail load obligation, and resells the wholesale purchase to its retail customers [30-32]. The LDC then passes on its wholesale procurement cost to those retail customers via dollar-per-kilowatt-hour ($/kWh) usage rates in its retail tariffs. For large customers, say those with monthly demand in excess of 500 kilowatts (kW), the usage rates may vary by time of use [33]. For small customers, this energy rate is often independent of time of use. In either case, however, the usage rates are pre-set to collect average procurement cost over a specific period, say a quarter, and customers can only respond to the periodic rate changes required to recover the LDC’s procurement cost. These periodic rate changes do not match the daily price variations in the wholesale spot markets. As a result, when the wholesale price exceeds the usage rate the LDC suffers a loss on every kWh that it purchases from the spot market for resale, and when the usage rate exceeds the wholesale price the LDC suffers an opportunity loss on every kWh that it might have purchased and resold to customers who would demand more electricity at any retail price below the usage rate. To be sure, the LDC may fully
recover its procurement cost eventually via subsequent rate adjustments. Nonetheless, the reality of daily divergence between retail rates and spot prices remains.

In recognition of the problem, a regulator like the California Public Utilities Commission may seek to introduce tariff proposals that can better transmit wholesale price signals to an LDC’s retail customers. Demand response by retail customers can mitigate the adverse impacts of potentially high and volatile wholesale prices in three specific and important ways. First, when consumer purchases decrease in response to higher prices, this reduces the output from generation units with high marginal production costs that drive the price offers of those units. Second, the decreased purchases mitigate capacity shortages, thus diminishing the above-marginal-cost markup (i.e., shortage cost) required to balance system demand and supply. Finally, since wholesale demand for electricity is a derived demand that responds to demand in the retail market, when retail buyers are sensitive to price so too are the wholesale buyers. That sensitivity counters the ability of the generators selling in the wholesale market to raise spot-market prices by withholding capacity at the same time that the LDC buyers are obligated to provide their customers with electricity upon demand.

The purpose of this paper is to explore various voluntary service options that encourage electricity consumers to respond to changes in wholesale prices by altering their electricity consumption. The options we explore are simple and practical, and make minimal information demands. They use readily available market data on spot prices and forward contracts. They do not require information on customer preferences, demand response to price changes, or customer outage costs due to electricity service disruption. The only key assumption made by the options’ design is that retail customers do not have upward-sloping demand curves. Simplicity,
practicality and generality mark this paper’s contribution to the literature on retail electricity pricing under deregulation.

2. The market environment and the design of retail rates

We consider an LDC that operates in a stylized market environment with the following characteristics:

- **Generation.** There is active trading in a daily electricity-generation market. The market may not be workably competitive and can have highly volatile spot prices.

- **Transmission.** An independent non-profit system operator (ISO) leases lines from the transmission owners and operates the grid under cost-of-service or performance-based regulation. The ISO provides transmission service for the resale of electricity under an open and comparable access tariff.

- **Distribution.** Each of several LDCs may own and operate its own local distribution network. Although end-users can, under retail access, fulfill their electricity needs from third-party suppliers, each LDC is obligated to provide safe and reliable service to those of its customers that decide explicitly or by default to receive bundled service from it. The LDC uses transmission service from the ISO to procure electricity from the generation spot and forward markets to meet its load obligations.

To establish that an LDC’s $/kWh charges may differ from wholesale market prices we make the following assumptions:

- **Retail tariffs.** Each LDC serves several classes of customers. The classes are mainly differentiated by size. Large customers face Hopkinson tariffs whose components include $/customer-month fixed charges, $/kW-month charges by time of use for current monthly
demands, a $/kW-month charge for historic ratchet demand, which compensates the LDC for providing local distribution service, and $/kWh charges by time of use that apply to current monthly kWh consumption. Small customers face simple tariffs with $/customer-month fixed charges, and time-invariant $/kWh charges that are applicable to current monthly kWh consumption. These retail tariffs aim to collect the LDC’s embedded costs of owning and operating its distribution network and cost of generation procurement.

- Procurement-cost recovery. As a price taker, the LDC procures prudently. Its procurement cost is recovered through the $/kWh charges in the retail tariffs. The average $/kWh charge for each customer class is set at its projected average procurement cost for a given period. That period may extend from a month to a year. When the average procurement cost in a given period deviates from the projection, the LDC seeks $/kWh rate adjustments that will become effective in the next period.

- Wholesale electricity spot-market prices. These spot-market prices are daily on-peak and off-peak prices whose definitions can differ from those used in the LDC’s retail tariffs. Spot-market prices vary daily and may exceed or fall below the $/kWh charges in the retail tariffs.

- Wholesale electricity forward-market prices. These prices are daily on-peak and off-peak prices for electricity delivered in the next period. LDC management may use the forward prices in one period to project the monthly average of daily on-peak and off-peak prices in the next period. It may also buy forward contracts to remove cost volatility due to spot-market purchases.

Taken together, the rate-making assumptions imply that the LDC’s $/kWh charges can deviate from the daily wholesale electricity spot-market prices, because they are based on fallible projections of average procurement costs. This deviation is the source of the economic gains to
be gotten via service options that induce customers to alter their demands for electricity in response to changes in the electricity spot price.

3. Pareto-superior demand-response rate options

Prior to deregulation many integrated utilities offered their customers such voluntary rate options as real-time pricing (RTP), time-of-use pricing (TOU), and curtailable/interruptible (C/I) service [34]. Profitable options are Pareto-superior because the utility’s shareholders benefit through improved earnings, and the end-users that select one of the options must also benefit *ex ante*, otherwise they would not have chosen to do so. Customers that eschew the option are no worse off as a result of its implementation.

3.1. The RTP option

Implementing RTP entails charging an end-user’s consumption at the real-time price at the electric node connected to that customer [35]. While mandatory RTP is economically efficient from a theoretical standpoint [36], as a practical matter it is not. First, transaction costs due to metering and billing are high, especially for small users. The efficiency gain from mandatory RTP is unlikely to be sufficient to offset those costs. Second, the efficiency gain assumes that consumers understand RTP and can make informed consumption decisions; but except for large industrial firms there is little evidence to support this assumption. Finally, competitive nodal prices may not exist due to the fewness of sellers at each node.

A simple form of mandatory RTP was implemented at the wholesale level via the mandatory England/Wales power pool formed immediately after the UK market reform. All generators had to bid into the England/Wales pool and the National Grid Company (NGC) dispatched all plants with capacity over 100 megawatts (MW). The NGC used the bids to set the
half-hourly purchase prices for distribution companies, each of which was the sum of the system marginal price for energy and a capacity cost. The latter was determined by the system loss-of-load probability (LOLP) times the average outage cost. Strategic bidding by the two largest generators, however, yielded noncompetitive prices and excess profit, an unintended outcome that calls into question the efficiency of a mandatory pool plagued by horizontal market power and collusion [37].

In contrast to the England/Wales power pool, the wholesale markets in North America do not mandate participation by all generators. The markets evolved from the bilateral trading that occurred among utilities in the 1980s. Deregulation and open-access policies in the 1990s led to the formation of major markets in the nine reliability councils formed after the 1967 blackout in the eastern part of North America.

An LDC may, however, offer an RTP option that can take advantage of volatile spot-market prices. An example is the two-part RTP option offered by B.C. Hydro in 1996, which benefits both the utility and its customers [38]. Since customer participation in the RTP program is voluntary, the option must be designed so as not to engender the sort of free-rider problem that allows the participants to obtain bill savings without changing their consumption behaviors. Free riders reduce the LDC’s revenue without producing any offsetting cost savings, thus resulting in a financial loss that may raise the rates for non-participating customers.

The two-part RTP option that discourages free riders operates as follows. In the first part, customers that choose the option pay a monthly fixed charge based on an unobserved hourly consumption profile that would have occurred absent the RTP option. This profile is commonly known as the customer baseline load (CBL). Under the assumption of stable consumption, the CBL can be reasonably proxied by a customer’s historical profile [38]. Hence, the fixed charge
in a given month, say March, is a customer’s historical profile for March billed at the standard
tariff, which for large users, for example, might be the Hopkinson tariff. Should the customer’s
total consumption exhibit systematic growth or decline, the CBL determination could be
modified to account for the systematic change.

The second part of an RTP customer’s monthly bill is a variable charge, which is the
monthly sum of hourly charges for hourly consumption deviations from the customer’s CBL.
For the sake of clarity, we focus on one hourly charge of \( V = p \Delta Q \), where \( \Delta Q = Q - Q^* \) is the
customer’s marginal hourly usage, or the difference between the customer’s actual (next-day)
consumption of \( Q \) and the historical hourly consumption level of \( Q^* \), and \( p \) is a day-ahead RTP
hourly energy rate. The customer’s actual consumption will depend upon this energy rate, set in
accordance to that hour’s spot-market price for energy with next-day delivery, denoted \( c \). An
example of such hourly spot-market prices are the on-peak (06:00 to 22:00, Monday to Saturday)
and off-peak (remaining hours) prices at the Pacific Northwest markets of Mid-Columbia and
California-Oregon-Border [22].

The RTP energy rate of \( p \) is set between the spot-market price of \( c \) and the standard
tariff’s energy charge of \( w \). This pricing strategy reflects the principle of shared gain. So long as
\( w \) differs from \( c \), the difference between the two provides an opportunity for economic gain.

Let \( \pi = (p - c)\Delta Q \) denote the incremental profit that an LDC earns from an RTP
customer’s marginal hourly usage of \( \Delta Q \). If the LDC can keep a portion of the realized profit, it
has an incentive to set \( p \) so as to ensure \( \pi \geq 0 \). Even if the LDC must pass 100% of any realized
profit to its customers, management still wants to earn a positive profit while avoiding any loss
that might invite a regulatory review, since such a review could result in cost disallowance [31].
To assure $\pi > 0$ management must set $p > c$ when that price will result in $\Delta Q > 0$, and $p < c$ when that price will result in $\Delta Q < 0$. But $\Delta Q$ depends upon both $p$ and $w$. In particular, as seen for a participant’s linear demand curve of Figure 1, setting $p = p_H > w$ results in $Q = Q_H < Q^*$ and $\Delta Q_H = Q_H - Q^* < 0$. Thus to earn a positive profit also requires that $c = c_H > p_H > w$. The alternative that sets $p = p_L < w$ results in $Q = Q_L > Q^*$, and $\Delta Q_L = Q_L - Q^* > 0$ requires $w > p_L > c = c_L$ for a positive profit.

Suppose, first, that $w > p_L > c_L$. When the energy rate is $p_L$, the customer wants to increase electricity usage above historical levels to $Q_L$. That customer pays the standard energy rate of $w$ for each unit up to $Q^*$, but only bears the variable cost of $p_L$ for each unit thereafter. The traditional measure of the customer’s benefit from the low spot-market price is the consumer surplus, which is defined by the triangular area labeled D in Figure 1. The LDC benefits to the tune of an incremental profit of $(p_L - c_L)\Delta Q_L$, which is represented by the rectangular area labeled E in the figure.

Alternatively, suppose that $c_H > p_H > w$. At the energy rate of $p_H$ the participant only demand $Q_H$ units of electricity. This reduction in usage below $Q^*$ means that the LDC will have to reduce the customer’s bill by $p_H\Delta Q_H$. In doing so, the LDC incurs a total procurement cost of $c_H Q_H$. Had the customer maintained usage at $Q^*$, however, the LDC’s procurement cost would have been $c_H Q^*$. Hence, even with the lower bill the LDC has saved itself $(c_H - p_H)\Delta Q_H$. This procurement-cost saving is the LDC’s RTP incremental profit with a high spot-market price. That profit is represented by the rectangular area labeled A in Figure 1.

Regardless of whether or not the RTP option is chosen, the end-user incurs a fixed hourly charge of $wQ^*$. The reduction in the customer’s bill when the option is chosen means that the customer enjoys a monetary saving of $(p_H - w)\Delta Q_H$. This saving is represented by the rectangular
area B + C in the figure, comprising the triangles B and C. But the reduction in electricity usage results in a loss of consumer surplus. That loss is represented by the triangular area C. Hence the net gain to the consumer is the difference between the two areas, or triangular area B.

The RTP option therefore benefits both the participants and the LDC. On the one hand, participating customers gain by increasing (reducing) their consumption in response to the low (high) prices that commonly prevail when there is an energy surplus (shortage), while non-participating customer are not affected. On the other hand, the LDC will enjoy either an increase in the profit that is earned from the participants, or a reduction in the loss that it would have incurred had those customers chosen not to participate in the RTP program. Moreover, when consumers respond to higher energy rates by reducing their electricity consumption, this in turn reduces the demand for electricity in the wholesale market, and this lower demand can result in lower spot-market prices. With no ill effects to be found, the two-part RTP option is Pareto-superior – at least \textit{ex ante}. It will also be Pareto-superior \textit{ex post}, provided that the end-user’s needs for electricity do not increase at a time when \( c > w \).

Specifically, when the end-user’s \textit{ex post} demand for electricity remains at \( Q^* \) during the current billing period, the bill will be the same with or without the RTP option. And when demand is lower, the end-user profits because of the rebate. Suppose, however, that even when \( c > w \) the end-user requires \( Q_H > Q^* \). This might happen when, for example, a manufacturer has to unexpectedly fill an order for a valued customer. In that case, the incremental cost of RTP to the end-user will be \( (p_H - w)\Delta Q_H > 0 \). The latter incremental cost is the exact amount by which the LDC benefits, since it fulfills the customer’s needs at the energy rate of \( p_H \) rather than at the standard tariff of \( w \), while incurring the same procurement cost of \( c_H \) in any event.
One can develop a variant of the two-part RTP option by replacing the daily-varying RTP energy rates with energy rates that are fixed for a given month based on the on-peak and off-peak forward prices settled at the end of the prior month. Those forward prices assume the role of the procurement cost in the initial RTP option. This variant is attractive to some customers because it does not have intra-month price volatility. As in Figure 1 and the preceding discussion, the on-peak (off-peak) fixed energy rate is set between the on-peak (off-peak) forward price and the tariff’s $/kWh charge for the on-peak (off-peak) hours defined in the forward contract. This variant is sometimes referred to as a two-part TOU rate option. It is included here because it is more closely akin to the two-part RTP than to the TOU option described below.

A second variant is a two-part TOU dispatchable-RTP option. This variant augments the two-part TOU rate option with high RTP energy rates to be dispatched by the LDC during extreme days of wholesale-market price spikes that exceed a preset threshold such as $0.50/kWh or $500/MWh that is higher than the forward prices used to set the TOU rates. Although the number of dispatch days may be subject to a preset limit such as “no more than 15 days per year,” the option enables the LDC to reduce a participating customer’s demand on extreme days. This is economic because if the LDC has to make a spot-market purchase to serve this customer, it suffers a loss equal to the difference between the wholesale-market price and the TOU rate. Even if the LDC has made enough forward purchases to exceed its load obligation, it can profitably sell the released kWh into the tight wholesale market that has produced the price spike.

3.2. The TOU option based on load shifting

The two-part RTP option can have wildly fluctuating rates for marginal consumption. Such price volatility is unattractive to risk-averse customers. The emergence of electricity
futures/forward prices, however, makes it possible for an LDC to offer a profitable TOU option based on load shifting. Similar to mandatory TOU pricing [39], this option uses price signals to encourage a participating customer to shift consumption from the on-peak period with high wholesale market prices to the off-peak period with low wholesale-market prices. The economic benefit from the consumption shift can be significant if the on-to-off-peak price ratio is large and induces substantial customer demand response.

An LDC offers the TOU option using the following steps [40]:

- The end-user’s on-peak and off-peak pre-TOU historical consumption shares are computed and the information is provided to the customer.
- Before the end of the current month, the LDC announces its projection of the on-peak and off-peak wholesale-market prices for the next month, based on the forward prices [22].
- Customers are informed of the pre-TOU per kWh cost of sales. Based on the forward prices, management determines the cost per kWh of sales to each customer before taking the TOU option. This cost, denoted \( \theta_0 \), is a weighted average of the wholesale prices, or procurement costs, projected by the LDC. The weights are the customer’s own pre-TOU consumption shares. Each customer is told its \( \theta_0 \).
- The LDC invites its customers to take the TOU option by offering an incentive based on consumption shifted from the on-peak to the off-peak period. Driven by the per kWh cost saving due to load shifting and the size of post-participation consumption, the incentive is a discount of the customer’s monthly total bill at the applicable tariff. Specifically, the discount is \( D = \alpha(\theta_0 - \theta_1) Q_{TOU} \), where \( \theta_1 \) = per kWh procurement cost for a customer that has chosen the TOU option, \( (\theta_0 - \theta_1) \) = per kWh cost reduction achieved by the shift in the
consumption pattern, and $\alpha = \text{fraction of the total cost savings that the LDC passes on to the customer who consumes } Q_{\text{Tou}} \text{kWh after taking the option.}$

The TOU option has four attractive properties. First, because the option is based on measurable savings, the computation of the customer’s discount is transparent and easy to understand. Second, the option completely eliminates free riders, since the discount is a fraction of the LDC’s cost savings. If there is no consumption shift and $\theta_0 = \theta_1$, the customer does not receive any discount. Third, the option discourages inefficient consumption. Should the customer consume relatively more in the on-peak period after taking the option, its bill could actually increase as $\theta_0 < \theta_1$. Finally, as the total procurement savings of $(\theta_0 - \theta_1) Q_{\text{Tou}}$ are shared by the end-user and the LDC, the TOU option is Pareto superior. Some customers, however, may decide against the option when the potential savings do not appear to be sufficient to outweigh its relative complexity and occasional inconvenience compared to the standard tariff.

3.3. The C/I Option

A C/I rate option is a call option that specifies conditions under which service disruption may occur. A customer entering into the contract gives the LDC the right but not the obligation to disrupt service. In exchange for the right, the LDC pays the customer an incentive through a bill reduction.

A C/I option implements the demand subscription service [41, 42] and priority service [43]. This option, which is popular in North America, requires a participating customer to specify a firm service level (FSL) that defines the reliability of the service provided to the participant. A participating customer’s kW demands below the FSL are considered to be firm and not subject to service curtailment. Demands above the FSL are curtailable in line with the
contract’s specifications. In exchange for the lower service reliability, the customer receives a price discount for non-firm service.

As a C/I rate option is a contract supplement to an LDC’s standard tariff, it often has the following attributes [44]:

- A FSL self-selected by a participating customer. The LDC may require the FSL to be less than the customer’s historical peak kW demand by a preset amount, so as to ensure that the customer’s participation is meaningful. Bluntly put, if the participating customer’s FSL is the same as the peak kW demand, the customer is in effect a non-participant that desires firm service.

- Conditions under which curtailment may take place. These conditions may include the following: (a) the advance notice, ranging from zero to 24 hours, to be given to a participant before curtailment can take place; (b) the maximum number of curtailments that may occur in a month, a season, or a year; and (c) the maximum number of unserved hours per curtailment.

- An up-front per kW incentive for the customer. This incentive defines the basis for computing the bill discount for the non-firm load, the kW demand above the FSL. For the option to be profitable to the LDC, the incentive per kW is set equal to a fraction of the per kW cost saving due to the customer’s acceptance of non-firm service. Hence the per kW incentive is

$$I = \beta S = \beta \gamma E[\text{Max}(c - w, 0)],$$

where \( \beta \) is a fraction to be determined by the LDC, \( S \) is the LDC’s per kW cost saving from not having to provide the service, \( \gamma \) is a customer-specific non-firm load factor that is equal to the ratio of the participant’s average non-firm kWs to its maximum non-firm kWs, and \( E[\text{Max}(c - w, 0)] \) is the expected loss avoided by one kW of flat non-firm load during the curtailment hours, or the call option value. The non-
firm load factor \( \gamma \) enters the calculation of \( I \) to account for the problem of “spiky” non-firm load that offers less load relief than does “flat” non-firm load.

- A performance incentive that defines the hourly per kWh incentive applied to excess load reduction \((FSL - \text{actual kW}) > 0\) during a curtailment. If the LDC also offers optional RTP, that incentive is the RTP energy rate.

- A penalty for a participant’s failure to curtail its load. If the LDC does not have direct control of a customer's load, it can only request curtailment and the customer will not necessarily comply with the request. To encourage compliance, a C/I contract should have a severe per kW penalty. That penalty will ordinarily be a multiple of the per kW incentive.

Given the contract specifications, the monthly bill for a C/I participant is the sum of the customer’s regular bill at the standard tariff and the penalty for non-compliance, less the bill reduction. The bill reduction is the sum of \((I \times \text{the non-firm demand})\) and \((FSL - \text{actual kW}) \times \text{the performance incentive}\). Since the reduction is designed to be less than the cost saving per kW, the C/I option is both rewarding to the participant and profitable for the LDC. Thus the option is Pareto superior \textit{ex ante}, although not necessarily \textit{ex post}.

Suppose, for example, that the spot-market prices for electricity are low and that no curtailment occurs. In this event the LDC suffers a loss since it has paid for a right to curtail service that it chooses not to exercise. By the same token, if the spot prices turn out to be high and curtailment occurs, the actual outage costs for a participating customer might greatly exceed the incentive payment that it has received from the LDC.
4. Conclusions

The three service options considered here share some common attributes. First, each option comprises a two-part design. The first part is a fixed charge that collects what a participating customer would have paid in the absence of the option. The second part is an incentive payment to the customer based on the gain to the LDC.

Second, each option is profitable because only a portion of the LDC’s gain is paid to the participating customer. The design principle of shared gains is based on the concept of the Nash equilibrium of a cooperative game [45].

Third, each option is designed so as to require readily available data on spot-market prices and the participant’s historical and billing-period consumption. Knowledge of customer preferences or price sensitivity is not required.

Fourth, all of the options are profitable for both the participant and the LDC ex ante, and hence are Pareto superior ex ante. To the extent that customers are rational and do not have upward-sloping demand curves or upon occasion increase usage despite higher prices, both the RTP and TOU options are certain to be Pareto superior ex post as well. The C/I option, however, will not necessarily be Pareto superior ex post.

Fifth, the options illustrate that Pareto superiority is inconsistent with the principle of marginal-cost pricing [46-47]. Pareto superiority requires each option to be profitable and profitability precludes the LDC from setting the optional RTP energy rate at the market price that reflects the marginal cost of generation. Along a similar vein, the incentive payments or bill credits of the TOU and the C/I option are only fractions of the total incremental profits to the LDC, and strict application of marginal-cost pricing would transfer all of those incremental profits to the participants.
Sixth, even if the LDC prudently manages its procurement cost and risk using electricity forwards [30, 32] and other hedge instruments, these options remain useful in aiding the LDC to profitably take advantage of the almost inevitable divergence between retail rates and wholesale electricity prices. This divergence is almost inevitable because the LDC’s retail rates generally do not vary instantaneously to perfectly match wholesale electricity prices.

Finally, the options might be offered in other market contexts such as one in which there is a regulated monopoly and no wholesale spot market. The option-design principles remain valid. Specifically, one can design options that replace the spot-market prices with the regulated monopoly’s marginal costs. The resulting options are useful insofar as they provide the consumer with voluntary incentive-laden service choices. Moreover, the options give the monopoly an opportunity to market and differentiate its products in anticipation of retail competition.

Alternatively, suppose the market context is one of complete retail access, without the LDC acting as a provider of last resort that supplies bundled service. Here, the LDC only sells local distribution service to retailers who buy wholesale electricity for resale. A basic product commonly sold by a retailer can be likened to a simple forward contract under which a customer pays for firm service at a flat price that does not vary by time of day. If all retailers were to offer flat-price contracts, they would only compete on price terms. To improve earnings, a retailer can differentiate its products by offering contracts that vary by price and contract length. Further differentiation adds the service options to the flat-price contracts. Hence the three options considered in this paper may also be useful to retail competitors.
References


Figure 1: Incremental profit of a two-part RTP option