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A Win–Win Mechanism for Electricity Procurement by a Local Distribution Company

A time-of-use rate option design allowing an LDC's customers to allocate their consumption to be billed at the fixed and daily-varying TOU rates offers a win–win mechanism for electricity procurement in the face of uncertain spot prices and hedging options. Even if all customers have the same risk preferences, the proposed mechanism is Pareto-superior to the tariffs and procurement strategies commonly used in North America.

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I. Introduction

Electricity market reform and deregulation have resulted in wholesale spot markets in Europe, Australia, New Zealand, and parts of North and South America.[1] Spot electricity prices are inherently volatile with sharp spikes, thanks to daily fuel-cost variations, especially for the natural gas now widely used by the popular combined-cycle gas turbines; weather-dependent and time-varying demands that must be met in real time by generation and transmission already in place; unpredictable and random output from renewable resources (e.g., solar and wind); changes in available capacity caused by planned and forced outages of electrical facilities; price manipulation during generation shortages; precipitation and river flow for a system with significant

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hydro resources; carbon-price variations that affect thermal generation using fossil fuels; transmission constraints that cause transmission congestion and generation redispatch; and lumpy capacity additions that can only occur with long lead times.[2]

A regulated local distribution company (LDC) procures electricity from the wholesale market for resale to meet the demands of its retail customers.[3] From a supply perspective, the LDC can mitigate its procurement cost risk by buying forward contracts, tolling agreements, and capacity options.[4] From a demand perspective,[5] the LDC can (1) offer reliability-differentiated tariffs that allow it to curtail sales when wholesale spot-market prices are high,[6] and (2) implement real-time pricing that passes on the wholesale spot prices to its retail customers.[7]

To manage its portfolio of supply resources and retail sales, LDC management considers the tradeoffs between the procurement cost expectation and its variance.[8] The optimal portfolio choice that drives the LDC's procurement plan, however, requires an assumption as to management's risk preferences,[9] which may be open to debate and challenge.

Even though the LDC may have been diligent in its procurement and risk management, it can still face the asymmetric risk of *ex post* prudence review by a regulator.[10] Under cost-of-service regulation, the LDC can at best recover its procurement spending.[11] If the LDC's hedging results in a large *ex post* loss, the regulator may disallow its recovery, thus harming the LDC's earnings. To minimize the risk of *ex post* cost disallowance, LDC management may decide not to hedge. Such a strategy, however, can backfire.

Under cost-of-service regulation, the LDC can at best recover its procurement spending.

In a rapid price escalation environment, a regulatory lag may cause the spot-market purchase cost paid by the LDC to far exceed the bill payments made by its customers, translating into a large loan from the LDC to those customers. If disallowed by the regulator, the unpaid loan can bankrupt the LDC.[12] In response to the spot- price volatility and spikes, the regulator (e.g., the California Public Utilities Commission) may require forward contracting by the LDC for the bulk (i.e., 95 percent) of its retail sales.[13] While the regulatory requirement may be justified by the presumption of customer preferences for known and stable rates, it is economically inefficient if some customers do not desire fixed prices for the bulk of their consumption.

This article presents an electricity procurement mechanism developed by a California-based contract-research firm that focuses on energy-related issues, for its local distribution company (LDC) clients. The mechanism integrates and extends studies done for LDCs in California, the Pacific Northwest, Florida, Missouri, British Columbia, and Israel in connection to electricity-rate options, electricity portfolio management, and procurement-cost recovery. It shows that even if an LDC's customers have identical risk preferences, the LDC can implement a win–win mechanism for electricity procurement in the face of uncertain spot prices and hedging options. Enabled by smart meters that record hourly consumption by each customer as part of the smart electricity grid initiative,[14] the mechanism integrates Pareto-superior time-of-use (TOU) rate options[15] into electricity portfolio management.[16] Since the mechanism induces the customers to reveal their preferences for fixed vs. daily-varying TOU rates, it helps determine the LDC's customer-driven procurement plan. Since the LDC's procurement plan is driven by customers' self-revealed preferences, it preempts the need and reason for *ex post* prudence review by a regulator.

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II. Tariff Design Choices

Consider an LDC that may procure from the wholesale spot market at daily prices $\$p_1$/MWH for delivery in a future *quarter* during the on-peak hours and $\$p_2$/MWH during the off-peak hours. Our assumption of two TOU spot prices reflects the bilateral day-ahead contracts traded in the United States.[17] Relaxing this assumption to the case of 24 hourly or 96 15-minute spot prices introduces algebraic complications into the exposition, without adding insight into the problem at hand. More specifically and as will be seen below, the only impact of delineating the spot prices by smaller and smaller time intervals is to arithmetically alter the calculation of a customer's electricity cost expectation and variance.

Our choice of a *quarterly* formulation reflects our interest in balancing the need for frequent price updates and the LDC's tariff administration cost. We do not consider monthly updates, which can be administratively cumbersome for both the LDC and its customers. Nor do we consider semi-annual updates, which require the LDC to procure forward contracts for six future delivery months, whose prices may be seen as non-transparent due to thin trading.

The LDC may also buy quarterly forward contracts at the fixed on-peak price of $\$F_1$/MWH and an off-peak price of $\$F_2$/MWH. Empirical evidence for the western region of North America indicates that the forward prices are 5-10% higher than the expected spot prices.[18]

Table 1 provides quarterly descriptive statistics for the daily spot prices in 2011 for delivery at SP-15 in Southern California. The correlation coefficients in Column (2) indicate moderate positive correlation between the on-peak and off-peak prices. Since the on-peak period is 06:00-22:00, Monday to Saturday (excluding holidays) and the off-peak period has the remaining hours, the quarterly number of days with on-peak hours in Column (3) is less than the number of days with off-peak hours in Column (7). It is seen in Columns (4) and (8) that the average on-peak prices are higher than the off-peak prices. It is further seen in Columns (5) and (9) that the daily on-peak prices are less volatile than the off-peak prices.

Each average price in Table 1 is the equally weighted average of the underlying daily prices. Based on the Central Limit Theorem, the average price is normally distributed with a variance equal to the variance of daily prices divided by the number of days used in the mean-price computation.[19] The variances of the average prices are small, as shown by Columns (6) and (10) in Table 1.

LDC management has the following tariff design choices, each of which ensures its procurement cost recovery:

Table 1: Descriptive Statistics for Daily Spot Prices in Southern California in 2011.

		On-Peak Price ($/MWh) during 06:00-22:00, Monday to Saturday, Excluding Holidays				Off-Peak Price ($/MWh) during Remaining Hours			
(1) Quarter	(2) Correlation between On- and Off-Peak Prices	(3) Number of Days	(4) Average of Daily Prices	(5) Variance of Daily Prices	(6) Variance of the Average Price	(7) Number of Days	(8) Average of Daily Prices	(9) Variance of Daily Prices	(10) Variance of the Average Price
1	0.71	76	35.84	11.56	0.15	90	22.67	36.15	0.40
2	0.52	77	35.90	20.65	0.27	91	13.09	38.70	0.43
3	0.35	77	41.65	17.21	0.22	92	25.78	25.50	0.28
4	0.40	77	33.88	7.67	0.10	92	25.23	3.96	0.04

Data source: https://www.theice.com/marketdata/reports/ReportCenter.shtml.

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(1) Set fixed TOU rates that match the forward prices F_1 and F_2. This choice reflects the fixed-rate tariffs commonly used by LDCs in North America.

(2) Set daily-varying TOU rates that match the spot prices p_1 and p_2. This choice reflects the mandatory real-time-pricing tariffs used by LDCs for their large customers in a restructured state like New York.

(3) Allow a customer to self-select between (1) and (2) as optional tariffs, where the chosen option will apply to the customer's entire consumption. This choice reflects the optional tariffs offered by the LDCs in states like California, New York, and Texas.

The third choice is Pareto-superior to the first two because a customer can self-select the tariff that best matches its preferences and willingness to take risk, without causing a financial loss to the LDC. With the advent of smart metering, however, it is welfare-dominated by our proposed design that allows a customer to allocate a *percentage* of its consumption to be billed at the fixed TOU rates and the remainder at the daily-varying TOU tariffs.

While conceptually similar to the ''index plus block'' service offered by a retail supplier in the restructured state markets,[20] our design simplifies a customer's allocation problem. This is because our design does not require the determination of a fixed-rate block, a potentially complicated task for a customer with an hourly-varying consumption pattern.

Under our proposed design, the management of an industrial electricity customer considers: (a) the certainty of pricing at known forward-market prices; (b) pricing based on the inherently uncertain and random prices of electricity spot markets; or (c) some combination of the two. As an analogy based on an employer-sponsored retirement investment plan (e.g., a 401K plan in the U.S.) with two investment choices (e.g., a money market fund and an SP500 index fund), (a) is akin to the money market fund, (b) is akin to the SP500 index fund, and (c) is akin to an allocation between the two funds, as commonly done in investment portfolio management.[21]

While conceptually similar to the ''index plus block'' service offered by a retail supplier in the restructured state markets, our design simplifies a customer's allocation problem.

One may argue that (c) is the same as the combination of (1) the LDC bills all customers at the daily-varying TOU rates, and (2) all customers can hedge using (financial) contracts for differences (CfD).[22] Such an argument, however, overlooks that the LDC may have millions of customers (e.g., SCE in California). And even if these customers are willing and able to trade CfD, the implementation of (1) and (2) is very costly when compared to (c), which is immediately implementable without the presence of a CfD market.

III. Optimal Allocation by a Customer

In principle, all customers of the LDC could be offered similar flexibility in their choice of billing options. For the sake of expositional clarity, however, we focus exclusively on industrial customers and their choice between the options, as illustrated by the example below.

Although built on a foundation of simplifying assumptions, our example serves to illustrate that even if all customers have the same risk preferences, they will likely have different consumption allocations between the two optional tariffs, chiefly because they have different on-peak consumption shares. Diversity in on-peak consumption shares is attributable to customer heterogeneity. For example, an industrial customer with one labor shift tends to have a higher on-peak consumption share than another user with three labor shifts. To the extent that these simplifying assumptions do not hold, the customers' allocations

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tend to be even *more* diverse than is implied here. For our two-tariff problem, however, the user's problem is to determine the optimal allocation – that is, the proportion α^* of total consumption – to be purchased at the daily-varying TOU rates.

We consider an industrial customer whose constant quarterly use of electricity is X comprising on-peak and off-peak shares of a_1 and $a_2 = 1 - a_1$. We assume that X and a_j are constant, for the following reasons. First, the assumption reflects the empirical evidence of the close-to-zero non-residential TOU demand-price responsiveness reported in the literature.[23] Second, it leads to a simple closed-form solution for the firm's allocation problem. Finally, relaxing this assumption does not alter the procurement mechanism that we propose in the next section.

Equation (5) of the appendix shows that the customer's optimal allocation α^* to the daily-varying TOU rates increases with the risk premium, which is the difference between the forward price F_j and the expected spot price μ_j, but decreases with the spot-price variance σ_j^2 and the correlation ρ between the on-peak and off-peak spot prices. Moreover, α^* is lower the greater is management's degree of risk aversion, θ. Thus, α^* captures the cost expectation and cost variance tradeoff made by the user's management.

Computing α^* requires a forecast of the statistics in Table 1. How to make such a forecast is well documented.[24] Since our focus is not on forecasting expected spot prices and their volatility, we use Table 1 for the sole purpose of demonstrating our key point: notably, even though the managements of two industrial customers have the same risk-preference function, as defined by equation (3) in the appendix, the two managements can arrive at different optimal allocations between the daily-varying-rate service and the fixed-rate service.

We use the descriptive statistics in Table 1 to compute α^* (at $\theta = 0.1$, $X = 1{,}000$ MWh, and $F_j = 1.05\mu_j$) for firms with different on-peak shares. Based on the results shown in **Table 2**, we find that the optimal allocation α^* varies with on-peak consumption share a_1, even though all firms have identical risk preferences. Moreover, firms with higher a_1 choose higher α^*, chiefly because the on-peak prices are less volatile than the off-peak prices. Finally, the α^* values in the fourth quarter are higher than those in other quarters because the fourth quarter has less-volatile prices. With these factors taken together, Table 2 confirms the cost expectation and cost variance tradeoff made by the customer's management.

IV. The Win–Win Procurement Mechanism

Having established that users tend to prefer different allocations despite identical risk preferences, we propose the following procurement mechanism:

- When first implementing the procurement mechanism, the LDC uses the α values that its customers already have. For example, a customer currently billed under daily-varying rates (fixed rates) has $\alpha = 0.0$ (1.0).

Table 2: Optimal Allocation α^* of Total Consumption to the Daily-Varying TOU Rates by On-Peak Consumption Share.

	On-Peak Consumption Share a_1								
Quarter	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1	0.0335	0.0353	0.0371	0.0390	0.0408	0.0426	0.0445	0.0463	0.0482
2	0.0197	0.0226	0.0255	0.0285	0.0314	0.0343	0.0372	0.0401	0.0431
3	0.0529	0.0560	0.0591	0.0621	0.0652	0.0683	0.0713	0.0744	0.0775
4	0.2952	0.3050	0.3148	0.3246	0.3343	0.3441	0.3539	0.3637	0.3734

Notes: The computation uses equation (5) under the following assumptions: (a) constant-risk-aversion coefficient $\theta = 0.1$; (b) total consumption $X = 1{,}000$ MWh; and (c) risk premium in the forward prices = 5% of the average spot prices in **Table 1**.

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• Near the end of a quarter (e.g., January–March 2013), the LDC helps a customer understand the next quarter's fixed TOU rates and the bill range based on historical data. Specifically, the LDC informs each customer of the fixed TOU rates for the upcoming quarter (i.e., April–June, 2013). The LDC also informs the customer of its past on-peak consumption share and total consumption for the same quarter of the prior year (i.e., April–June, 2012). Finally, the LDC provides a comparison of the customer's bills under the prior year's fixed rates and daily-varying rates. Thus, the information provided by the LDC resembles what an administrator of a 401K plan would provide in the quarterly statement to each 401K account owner.

• Before a customer can receive service in the upcoming quarter, it selects its preferred α of its total consumption in a future quarter to be billed at the daily-varying TOU rates. The remaining $(1 - \alpha)$ is billed at the fixed TOU rates. If the customer does not make an explicit selection before the quarter begins, its α value in the prior year is used, similar to the automatic rollover of a three-month CD held by an investor. When the chosen α is 0.0 (1.0), the customer confirms that it has chosen to have all of its consumption billed at the daily-varying (fixed) TOU rates. While the α selection induces each customer to reveal its risk preferences, it is not necessary for the LDC to know how each customer chooses its α value or its demand response to the daily-varying TOU rates.

• After receiving each customer's self-chosen α values, LDC management estimates the total amount of electricity to be bought from the forward market. This estimation has the following steps: (1) find the LDC's aggregate past sales by TOU period, or $\Sigma_k Q_{jk}$, where Q_{jk} is the past quarterly consumption of customer k $(= 1, \ldots, K)$ in period j $(j = 1, 2)$; (2) find the share of aggregate past sales at the customers' self-chosen a values: $S_j = \Sigma_k \alpha_k Q_{jk} / \Sigma_k Q_{jk}$, where α_k is the value of α that is chosen by customer k; and (3) estimate the forward-market purchase $Y_j = (1 - S_j) Z_j$, where Z_j is the forecast of total sales by TOU period. While step (3) requires that the LDC forecast its total sales, it reflects what is now done by LDCs in North America.[25]

• The LDC submits its procurement plan that has the TOU forward-purchase estimates to the regulator for timely approval, as is now done in California.

• The LDC executes the approved forward purchases to meet a portion of its total sales, and buys from the spot market for the remaining sales.

• The LDC bills its customers based on their self-chosen α values, using the hourly consumption data recorded daily by the smart meters.

Our proposed mechanism preempts *ex post* prudence review of the LDC's forward-market purchase, because the LDC has pre-approval from the regulator for the customer-driven procurement plan. The LDC makes zero profit because of the 100 percent pass-through of its procurement cost to its customers.

The mechanism implements a win–win strategy. This is because if some customers choose α values between 0 and 1, their revealed preferences indicate that they have been made better off *ex ante* when compared to the status quo of having 100 percent of their consumption priced at the fixed or daily-varying TOU rates. To be sure, the mechanism does not guarantee *ex post* Pareto superiority as some customers may suffer an *ex post* loss relative to their status quo, as in the case of other types of rate options.[26]

V. Conclusion

Recognizing that wholesale spot-market prices are highly

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volatile, we propose a TOU rate option design that allows an LDC's customers to allocate their consumption to be billed at the fixed and daily-varying TOU rates. The customer-chosen allocations inform the LDC as to the amount of electricity to be bought from the forward market. Even if all customers have the same risk preferences, our proposed mechanism is Pareto-superior to the tariffs and procurement strategies commonly used in North America. Since the LDC's procurement plan resulting from the mechanism is driven by customers' self-revealed preferences, it preempts the need and reason for *ex post* prudence review by a regulator.

We would be remiss if we fail to discuss future extensions of our proposed mechanism. First, the quarterly tariff update can be made into a menu of update frequencies for customer self-selection. For instance, a customer may choose to have monthly, bi-monthly, quarterly, semi-annual, or annual updates. The update-frequency choices are largely limited by the LDC's tariff administrative cost and the forward market's trading and price discovery.

Second, the LDC may allow its customers to have different α allocations by TOU period. At no cost to the LDC, this extension gives more flexibility to customers in their management of electricity cost expectation and risk.

Finally, the LDC may expand the set of TOU tariffs with a different number of TOU periods. This extension aims to reflect the presence of multiple spot markets. For example, California has, besides bilateral trading of on-peak and off-peak electricity, an hourly energy market operated by the California Independent System Operator that daily yields 24 hourly prices. The LDC may offer four TOU tariff options: (1) fixed on-peak and off-peak rates; (2) variable on-peak and off-peak rates; (3) 24 fixed hourly rates; and (4) 24 variable hourly rates.

To conclude, the LDC can exploit an advanced metering infrastructure's metering and billing capabilities to offer a wide spectrum of TOU tariff options that its customers can self-select for their electricity cost/risk management. The customer preferences thus revealed will ensure the LDC's prudent procurement, thereby ensuring the LDC's cost recovery.

Appendix A

Consider an industrial customer that requires x_1 MWH of electricity per day for N_1 days during the wholesale market's on-peak hours and x_2 MWH per day for N_2 days during the wholesale market's off-peak hours. The customer's quarterly total consumption is $X = (x_1N_1 + x_2N_2)$. The quarterly consumption share in period j is $a_j = x_jN_j/X$ for $j = 1$ (on-peak), 2 (off-peak). By construction, $a_2 = 1 - a_1$.

If the firm's entire consumption is priced at the daily-varying TOU rates, its quarterly electricity cost at the average daily prices P_1 and P_2 is:

$$C_P = (a_1P_1 + a_2P_2)X.$$

If we were to consider J (e.g., 24) spot prices, then the quarterly electricity cost would be $(\Sigma_j a_j P_j)X$.

Since each quarterly average of daily prices is normally distributed, the customer's quarterly cost is also normally distributed, a useful empirical fact for deriving the firm's optimal allocation below.

Let μ_j denote the expected average daily price, σ_j^2 the variance of the average daily price, and ρ the correlation between the daily prices. The customer's quarterly cost expectation at the spot prices is:

$$\mu_P = (a_1\mu_1 + a_2\mu_2)X. \quad (1.a)$$

The cost variance is:

$$\sigma_P^2 = (a_1^2\sigma_1^2 + a_2^2\sigma_2^2 + 2a_1a_2\rho\sigma_1\sigma_2)X^2. \quad (1.b)$$

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Again, if we were to consider J TOU pricing periods, the cost variance would become $(\Sigma_j \Sigma_k \sigma_j \sigma_k \rho_{jk}) X^2$, where σ_j is the standard deviation of the daily average price for period j and ρ_{jk} is the correlation between the two daily spot prices in periods j and k.

When the on-peak and off-peak prices are positively correlated and the on-peak spot prices are higher and more volatile than the off-peak spot prices, μ_P and σ_P^2 increase when the customer uses relatively more on-peak electricity.

If the customer's entire consumption is priced at the fixed TOU rates, its electricity cost expectation is fixed at:

$$\mu_F = (a_1 F_1 + a_2 F_2) X. \tag{1.c}$$

Now suppose each customer can allocate a fraction, α, of its electricity consumption to be billed at the daily-varying TOU rates and $(1-\alpha)$ at the fixed TOU rates. With this allocation, the customer's electricity cost expectation is:

$$\mu = \alpha \mu_P + (1-\alpha)\mu_F. \tag{2.a}$$

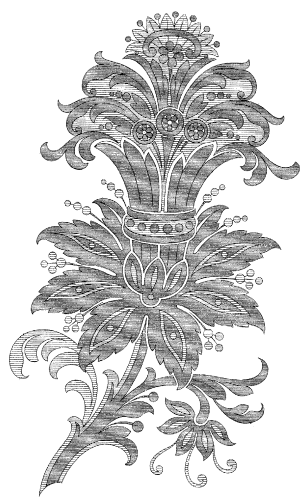
The associated cost variance is:

$$\sigma^2 = \alpha^2 \sigma_P^2. \tag{2.b}$$

Let R denote that customer's quarterly net revenue, save for the uncertain cost of electricity, which is $C = \alpha C_P + (1-\alpha)\mu_F$. The customer's quarterly profit is $\pi = R - C$. We assume that management's willingness to take risk is captured through the risk-preference function of equation (3):

$$\begin{aligned} V &= K_1 - \exp(-\theta\pi) \\ &= K_1 - \{\exp(-\theta R)\} \\ &\quad \times \{\exp(\theta C)\} \\ &= K_1 - K_2 \exp(\theta C). \end{aligned} \tag{3}$$

That is, the firm's management is constantly risk averse, with $\theta > 0$ the degree of risk aversion in the Arrow-Pratt



sense,[27] and will seek to determine the allocation, α^*, that maximizes $E[V]$.[28]

Since C_P is normally distributed, C is also normally distributed. After minor algebraic manipulation under the integral sign during the expectations process, management makes its *ex ante* allocation decision by maximizing its expected-utility function:

$E[V] = K_1 - K_2 E[\exp(\theta C)]$
$= K_1 - K_2 \exp(\theta\mu + \theta^2\sigma^2/2)$.

The first-order condition for a maximum $E[V]$ is:

$$\begin{aligned} dE[V]/d\alpha &= -K_2[\theta(d\mu/d\alpha) \\ &\quad + \theta^2(d\sigma^2/d\alpha)/2] \\ &\quad \times [\exp(\theta\mu + \theta^2\sigma^2/2)] = 0. \end{aligned}$$

The latter immediately reducesto:

$$(d\mu/d\alpha) + \theta(d\sigma^2/d\alpha)/2 = 0 \tag{4}$$

Now, from (2.a), $(d\mu/d\alpha) = \mu_P - \mu_F$; and from (2.b), $d\sigma^2/d\alpha = 2\alpha\sigma_P^2$. After substituting these terms into equation (4), we determine:

$$\begin{aligned} \alpha^* &= (\mu_F - \mu_P)/\theta\sigma_P^2 \\ &= [a_1(F_1 - \mu_1) + a_2(F_2 - \mu_2)]/ \\ &\quad [(a_1^2\sigma_1^2 + a_2^2\sigma_2^2 \\ &\quad + 2a_1a_2\rho\sigma_1\sigma_2)X\theta]. \end{aligned} \tag{5}$$

It is easily verified that the second-order condition for a maximum is satisfied where the first-order condition holds.■

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