NBER WORKING PAPER SERIES

WEALTH TRANSFER FROM IMPLEMENTING REAL-TIME RETAIL ELECTRICITY PRICING

Severin Borenstein

Working Paper 11594
http://www.nber.org/papers/w11594

NATIONAL BUREAU OF ECONOMIC RESEARCH
1050 Massachusetts Avenue
Cambridge, MA 02138
August 2005

Director, University of California Energy Institute (www.ucei.org); E.T. Grether Professor of Business Administration and Public Policy at the Haas School of Business, University of California, Berkeley (faculty.haas.berkeley.edu/borenste) and National Bureau of Economic Research (www.nber.org). Email: borenste@haas.berkeley.edu. For helpful comments and discussions, I am grateful to Jim Bushnell, Claude Crampes, Stephen Holland, Rob Letzler, Karen Notsund, Catherine Waddams and Frank Wolak. The views expressed herein are those of the author(s) and do not necessarily reflect the views of the National Bureau of Economic Research.

Wealth Transfers from Implementing Real-Time Retail Electricity Pricing
Severin Borenstein
NBER Working Paper No. 11594
August 2005
JEL No. L9

ABSTRACT

Adoption of real-time electricity pricing — retail prices that vary hourly to reflect changing wholesale prices — removes existing cross-subsidies to those customers that consume disproportionately more when wholesale prices are highest. If their losses are substantial, these customers are likely to oppose RTP initiatives unless there is a supplemental program to offset their loss. Using data on a random sample of 636 industrial and commercial customers in southern California, I show that RTP adoption would result in significant transfers compared to a flat-rate tariff. When compared to the time-of-use rates (simple peak/offpeak tariffs) that these customers already face, however, the transfers drop by nearly half; even under the more extreme price volatility scenario that I examine, 90% of customers would see changes of between a 9% bill reduction and a 14% bill increase. Though customer price responsiveness reduces the loss incurred by those with high-cost demand profiles, I also demonstrate that this offsetting effect is unlikely to be large enough for most customers with costly demand patterns to completely offset their lost cross-subsidy. The analysis suggests that adoption of real-time pricing may be difficult without a supplemental program that compensates the customers who are made worse off by the change. I discuss how "two-part RTP" programs, which allow customers to purchase a baseline quantity at regulated TOU rates, can reduce the transfers associated with adoption of RTP.

Severin Borenstein
Haas School of Business
University of California
Berkeley, CA 94720-1900
and NBER
borenste@haas.berkeley.edu

I. Introduction

With the restructuring of electricity markets, and the disruptions that resulted in some locations, there has been an increasing focus on efficient pricing of electricity. At the retail level, there have been studies and public policy discussions of real-time pricing (RTP) – retail prices that vary hour-to-hour, reflecting wholesale price variation. Among economists and some policy makers there is widespread agreement on the potential benefits of RTP. There is, however, uncertainty about full economic impact of RTP. Beyond the real economic costs of implementing RTP – such as installing sophisticated meters and adapting to more complex billing – the resulting wealth transfers also create potential political barriers.

Wealth transfers from moving to RTP would occur because current billing practices – a constant price at all times or simple peak/off-peak pricing (known as time-of-use or TOU pricing) – do not cause retail prices to fluctuate as much as they probably would under RTP. Under current billing approaches, customers who consume disproportionately high quantities when wholesale prices are high are subsidized by those who consume disproportionately low quantities at those times.

In this paper, I investigate the size of the wealth transfers that would occur if electricity systems were to change from billing large commercial and industrial customers under the simple retail pricing structures currently in use to billing them under a real-time pricing structure. I focus in this paper only on wealth transfers. In other work, I and others have estimated the size of potential efficiency gains from RTP.[2] While efficiency gains are clearly important, policy discussions of RTP proposals are frequently derailed by concerns that some customers would be harmed significantly by ending the cross-subsidy implicit in the current billing structures. My goal in this paper is to characterize the magnitude of the transfers that would occur with implementation of RTP.

Using a dataset of realtime consumption patterns of more than 600 large customers in southern California, I analyze their retail electricity costs under alternative billing approaches. I find that moving from a flat rate to RTP would indeed cause significant wealth transfers. Decomposing this effect, however, I find that much of the transfers that would

[2] See Borenstein (2005a), Borenstein (2005b), Borenstein and Holland (forthcoming), and Holland and Mansur (2005).

result from a switch from a flat-rate tariff to RTP occur even with movement from flat rates to TOU, a change that has already taken place for most large customers in the U.S. The additional transfers due to further increasing the time-sensitivity of retail pricing from TOU to RTP may be comparatively small.

I then investigate how much the potential losers in a switch to RTP may be able to overcome the loss of cross-subsidy by being price responsive. That is, even if a customer has a relatively costly demand profile – consuming larger quantities at times when the wholesale price is high – it might be able to offset that loss through efficiency gains that occur when it sees the actual real-time electricity price and responds. The results of this analysis, however, suggest that the effect of a customer's own price response on its bill are likely to be small compared to the transfer effect unless the customer exhibits quite high price elasticity.

The results suggest that it may be important to mitigate the wealth transfers from RTP adoption in order to build a broad enough political coalition for its adoption. Where RTP has been adopted, it has often included a "baseline" component that allows an RTP customer to continue purchase a fixed quantity of power at the regulated TOU rates. I explain how such programs reduce the wealth transfers that would otherwise accompany RTP adoption and by doing so probably contribute to their acceptance.

In the next section, I explain how I calculate retail rates under alternative billing regimes. In section III, I explain the data used for customer demands and wholesale prices. The results with non-price-responsive RTP customers are presented and analyzed in section IV. In section V, I extend the analysis to allow for price responsiveness by the customers who are charged real-time prices. I discuss the political economy implications of the results in section VI and examine how "two-part" RTP programs that include a baseline quantity purchase at regulated rates reduce the wealth transfer from RTP adoption. I conclude in section VII.

II. Alternative Retail Billing Arrangements

Historically, electricity customers have been billed according to one of two general rate designs: a time-independent "flat" electricity price or a time-of-use (TOU) price structure that charges higher rates during pre-designated "peak" times and lower rates at other times. Nearly all large electricity users are charged according to a TOU rate.[3]

Flat electricity rates impose a standard per-kilowatt-hour rate that is charged at all times of the day, week, and year, while it is in force. Time-of-use rates can be as simple as charging a different rate during high demand months than during low-demand months, but in practice are generally more complex. The time-of-use rate structures faced by most of the customers I study here have five different price levels based on the time of year and the day/time of the week. There is a winter rate structure with a peak price in effect from 8am to 9pm on non-holiday weekdays and an off-peak rate in effect at all other times. Winter runs approximately October through May. Summer rates, which are in effect approximately June through September, have three components: Peak period is noon-6pm on non-holiday weekdays; Shoulder period is 8am-noon and 6pm-11pm on non-holiday weekdays, and off-peak is all other times. In my analysis of TOU rates, I assume that the tariff includes these same five TOU periods.[4]

Clearly, because the wholesale cost of electricity varies by the hour, there are likely to be significant cross-subsidies present in retail rates that vary substantially less often. In addition, there are often cross-subsidies across classes of customers: residential versus commercial/industrial, high versus low cost locations, and low-usage versus higher-usage customers. Charging retail customers real-time wholesale energy prices for the electricity they consume would eliminate cross-subsidies within the energy portion of their bills.

In order to focus on the effect of the rate design, I abstract from other subsidies that the political rate-making process might include in the rates. For the group of customers I observe, I assume that each of the rate structures considered – flat, TOU and RTP – raises total revenue from these customers that exactly equals the total wholesale cost of the power they consume. For a given set of wholesale prices, that is sufficient to fully specify the flat and RTP rates.

---

[3] Customer bills also include a component for transmission and distribution of electricity as well as the energy component. I do not consider the T&D component of the tariff, which often includes a demand charge that is a function of the customer's peak usage during a period, as there is currently little or no policy discussion of changing that.

[4] In the three year period I study, the number of hours each rate is in effect are: winter off-peak, 11007 hours; winter peak, 6513 hours; summer off-peak, 4959 hours; summer shoulder, 2295 hours; summer peak, 1530 hours.

The TOU rate, however, requires further specification, as there are many different rates for the five TOU periods that would attain the revenue neutrality target. I start by assuming that there is no cross-subsidy across the TOU periods. The resulting TOU rate schedule has a somewhat larger peak-to-offpeak price variation than exists in actual tariffs, however, so I also consider a TOU tariff with a ratio of prices between periods that is closer to the ratios in tariffs that are actually in use.

III. Demand and Price Data

In order to estimate the potential size of wealth transfers under RTP, one needs to have data on the demand patterns of individual customers and to analyze how a customer's demand co-varies with the wholesale price of electricity.[5] I have obtained hourly customer-level consumption for 636 lage industrial and customers of Southern California Edison.[6] The data cover June 2001 through December 2004, though not all customers are in the dataset for that entire period either because the business opened or closed during that period, or because they did not have a real-time meter for that entire period. Because few of the customers were in the program at the start, and to have a seasonal-balanced dataset, I use data for January 2002 through December 2004.

I start by using the simplest approach to analyzing transfers, assuming that each customer's demand is completely price inelastic and looking at their payments under alternative billing regimes. I do this for concreteness, as elasticity estimates are controversial and there is no credible way to infer customer-level demand elasticities with any precision. Still, in section V, I assume various levels of demand elasticity – though still the same level for all observed customers – and examine the extent to which introducing such elasticity reduces the losses incurred by those customers that would be harmed by a switch to RTP.

The value of this whole exercise depends on the plausibility of the distribution of wholesale prices assumed. One could use the actual California prices from the same time period as the customer-level data. While these prices have some credibility, there is a real

---

[5] In discussing this covariation, I am not suggesting causality, since the customers don't actually face these prices.

[6] These customers were randomly selected among all those in the utility's service area that had peak demand of at least 200kW and therefore qualified under 2001 state legislation to receive free installation of a real-time meter.

issue of how representative they are of likely prices in the future. In particular 2002 to 2004 prices in the California spot market are widely viewed as having been below long-run equilibrium levels. The emergency building of capacity in response to the California electricity crisis brought online so many new power plants that operators argued prices were then too low to justify further building. A glut of capacity would almost certainly damp peak prices more than off-peak prices, so using these prices would lead to an understatement of the wealth transfer effect that introduction of RTP would have. Thus, while I carry out the analysis using actual spot prices, I view this as a representation of low price volatility in long-run equilibrium. Thus, using this price series is likely to understate the magnitude of transfers that would result.

In response to this concern, I also study potential transfers that would result using simulated long-run equilibrium wholesale prices. The simulations are based on the model presented in Borenstein (2005a). The model establishes a long-run perfectly competitive equilibrium in capacity and wholesale prices for a given demand profile (load duration curve), assumed demand elasticity, and costs of different types of production capacity. The data used for generating the wholesale price series for this paper are not exactly the same as in Borenstein (2005a). First, I use different cost data than those in the earlier paper, reflecting changes in capital and fuel costs since that paper was written.[7] Second, I use only demand data from the 3-year period 2002-2004. By limiting the time period of simulation to just January 2002 through December 2004, I can impose that the resulting prices are sufficient in aggregate to cover the amortized capital and variable costs of all generators during the sample time period.

Absent large elasticity for aggregate demand, much of the capital costs are recovered in peak hours, though exactly how many hours and how peaky the prices are depends on the exact elasticity of aggregate demand. I create two wholesale price series with differing elasticities of aggregate demand and different resulting peakiness of prices. I give statistics on the resulting prices below.

---

[7] The assumptions I use here for annual production cost are: Baseload (coal) Cost = $\$208247/MW + \$25/MWh$; Mid-merit (CCGT) Cost = $\$93549/MW + \$50/MWh$; and Peaker (Combustion Turbine) Cost = $\$72207/MW + \$75/MWh$. These figures are taken from the PJM (2005), pages 82-83. California does not have coal plants, but (a) there are coal plants in the western grid and (b) the results are not affected substantially by fixing the level of baseload capacity in advance to reflect nuclear and other must-take capacity.

Table 1: Wholesale Prices in Alternative Scenarios
(all prices in $/MWh)
Time Period: 2002-2004, 26304 total hours

		Scenario I Very Volatile Simulated Prices	Scenario II Less Volatile Simulated Prices	Scenario III Actual Southern California Prices
Flat-Rate Tariff		93.17	92.96	75.25
TOUA Tariff – Maintaining Actual Price Ratios Among TOU Periods				
Winter	Off-Peak	79.29	79.11	64.04
Winter	Peak	102.89	102.66	83.10
Summer	Off-Peak	74.80	74.63	60.41
Summer	Shoulder	95.41	95.20	77.06
Summer	Peak	166.22	165.85	134.25
TOUB Tariff – Breakeven within Each TOU Period				
Winter	Off-Peak	69.69	69.70	70.13
Winter	Peak	90.13	90.71	84.55
Summer	Off-Peak	76.59	77.41	66.54
Summer	Shoulder	98.55	106.42	74.53
Summer	Peak	258.87	240.35	85.53
Real-time Pricing Tariff				
Minimum Price		65.00	65.00	10.09
Median Price		90.00	88.73	73.03
Mean Price		88.77	88.77	74.19
Maximum Price		16146.41	1525.44	262.39
Number of Hours Price is Above Highest Simulated Generation Marginal Cost		205	1289	N/A

For each of these price series, I also had to create a flat-rate tariff and time-of-use tariffs as the comparison points for calculating the transfers. To do so, I considered the 636 customers as a distinct customer class and calculated the rates, flat and TOU, that would exactly cover the wholesale cost of acquiring wholesale power for this customer class. For each wholesale price series, I have calculated a single break-even flat rate. I have calculated two different sets of TOU rates. The first permits no cross-subsidy across the five TOU periods; I refer to this as "Breakeven Periods TOU" or TOUB. The second places a constraint on how much TOU rates can vary between periods so the ratio of rates between periods is approximately equal to the ratio in Southern California Edison's most common TOU tariffs; I call this "Actual Ratio TOU" or TOUA. All or these tariffs are set to assure that the revenue received exactly covers the wholesale cost of power.

Table 1 presents the flat retail price and TOU retail prices under the three different wholesale price distribution assumptions, as well as data on the distribution of wholesale prices for each case. Scenarios I and II, with simulated prices, reflect different degrees of wholesale price volatility depending on the elasticity of the aggregate demand faced by producers in the market. This aggregate demand elasticity could result from retail price responsiveness from end users or it could be caused by supply elasticity from imports. With less elasticity, *i.e.,* scenario I, peaker generating plants recover their fixed costs in fewer hours with higher prices; the peak price is substantially higher in scenario I than scenario II and the price is above the marginal cost of the simulated peaker generators in substantially fewer hours.[8]

Scenario III uses the actual wholesale prices from the California ISO's real-time balancing market for the area in which the observed customers are located. As mentioned previously, the actual wholesale prices over this period exhibited very little volatility. I do not include information on the number of hours in which prices exceeded the marginal cost of peaker generation, because there is no reason to think that generators actually earned rents that exactly covered their amortized capital costs during this period.

I present these scenarios separately from the later analysis in which the *observed* customers are assumed to be able to demonstrate some price responsiveness in order to distinguish between two effects that will mitigate the size of transfers. The first effect is from aggregate demand elasticity that damps price volatility, as is demonstrated in the difference between scenarios I and II, the effect of which is discussed in the next section. The second effect is from a customer itself responding to volatile prices by consuming less at peak times and more at off-peak. For the observed customers, I ignore this second effect in section IV, but return to it in section V.

IV. Transfers from RTP Adoption if Customers Are Not Price Responsive

I calculate the electricity bills for each of the 636 customers in the dataset under the four alternative billing arrangements using each of the wholesale price scenarios. The bills include a flat charge for transmission and distribution of \$40/MWh. The T&D charge has

[8] I do not report this last statistic for the actual southern California prices, because comparison to the simulated cost assumptions wouldn't be meaningful and I don't have cost data for all of the peaker generators in the California electricity grid.

no effect on the magnitude of the transfers, but I include it in order to give a more accurate picture of the proportional impact from changing billing arrangements on the customer's electricity bill. On average T&D comprises slightly less than half of the electricity bill, so the proportional changes in just the energy component of customer bills are slightly more than twice as large. Throughout the calculations in this section, I assume that customers make no change in their consumption in response to changes in the billing arrangement.[9]

For each wholesale price scenario, each customer's payments under RTP can be compared to their payments under a flat rate billing arrangement with the same wholesale price series. Of course, some customer bills increase compared to flat rates and others decrease, while the total revenue collected from this class of customers is held constant by construction. The distribution across customers of percentage gains and losses is shown in the first line under each scenario in Table 2. The most volatile simulated prices (scenario I) result in transfers under RTP are the most extremes upper and lower distribution tails. Under all three scenarios, there could be substantial winners and losers, with the worst off percentile of the distribution possibly facing bill increases of more than 50% compared to a completely flat rate billing arrangement if there were no price response by the customer.

It is worth noting that the median of these customers pays more under RTP than under flat rates – again, before accounting for any price response. This is because the largest electricity users tend to have flatter loads and thus to be winners from the switch to RTP. Since the quantity-weighted revenues are unchanged, by construction, the fact that the biggest customers are winners means that there are more customers that are losers than winners.

The transfers shown in scenario I, the most volatile wholesale price scenario in table 2, suggest that there could be substantial opposition, with one-quarter of the customers seeing their bills rise by 10% or more (as indicated by the 75th percentile change in bills). Scenario II, with less volatile wholesale prices, shows transfers that are nearly as large as under scenario I. This is evident from the percentile bill changes.

The magnitude of total transfers is indicated by the right-hand column of table 2.

9 By assuming that T&D is charged at a flat rate, I ignore the impact of demand charges that are part of T&D. Demand charges are a fee calibrated to the customer's peak usage during a given period. To the extent that a customer's usage is correlated with system demand, demand charges increase the size of transfers associated with departing from flat rate electricity billing.

Table 2
Distributions of Change in Customer Bills Compared to Flat-Rate Tariff
(636 Customers)

	PERCENTILES 1st	5th	10th	25th	50th	75th	90th	95th	99th	Total Absolute Transfers ($mil)
Scenario I: Very Volatile Simulated Wholesale Prices										
RTP	-17%	-12%	-8%	-2%	4%	10%	16%	21%	59%	123.5
TOUB	-15%	-9%	-4%	0%	4%	9%	13%	15%	20%	91.1
TOUA	-9%	-5%	-3%	-1%	2%	5%	8%	9%	11%	54.4
Scenario II: Less Volatile Simulated Wholesale Prices										
RTP	-16%	-10%	-6%	-1%	4%	9%	15%	18%	29%	103.4
TOUB	-14%	-9%	-4%	0%	4%	8%	12%	14%	19%	86.0
TOUA	-9%	-5%	-3%	-1%	2%	5%	8%	9%	11%	54.3
Scenario III: Actual Southern California Wholesale Prices										
RTP	-6%	-4%	-2%	0%	2%	3%	5%	7%	11%	27.9
TOUB	-5%	-3%	-1%	-1%	1%	2%	3%	4%	5%	19.9
TOUA	-9%	-5%	-3%	-1%	2%	5%	8%	9%	11%	44.0

Distributions of Change in Customer Bills from TOUA to RTP
(636 Customers)

	PERCENTILES 1st	5th	10th	25th	50th	75th	90th	95th	99th	Total Absolute Transfers ($mil)
Scenario I	-12%	-9%	-7%	-2%	2%	5%	9%	14%	50%	77.4
Scenario II	-9%	-6%	-4%	-1%	2%	4%	7%	10%	22%	55.1
Scenario III	-7%	-5%	-4%	-3%	-1%	1%	3%	5%	10%	26.9

This column shows the aggregate *absolute value* of bill changes for the 636 customers. A switch from flat rates to RTP under scenario I, for instance, would bring about a total transfer of about $124 million among these 636 customers over the three-year period. The first row of scenario II shows that the transfers would be about $103 million with that set of wholesale prices, only 16% smaller than in scenario I. The transfers would be much smaller if the actual wholesale prices that obtained during this period, scenario III, were indicative of future prices, $28 million over three years, 77% less than under scenario I.

Even continuing to ignore the price-dampening effect of RTP, however, the actual bill changes would be much smaller than the figures in the right-hand column. The reason is that all of these large customers are already on TOU rates. So, from a political economy viewpoint, the relevant change is from TOU to RTP. As mentioned earlier, I use the five TOU time periods (3 periods in summer, 2 in winter) under two different sets of TOU rates for this "customer class" of 636 customers; one set of rates (TOUB) is set so that each time period meets its own separate revenue requirement, the other set (TOUA) meets the revenue requirement overall while maintaining preset percentage price differences among the time periods.

Focusing first on scenario I, it is clear that a shift from flat rates to TOU pricing imposes a significant proportion of the transfers that would occur by moving all the way to RTP, but what proportion depends very much on the type of TOU. TOUB, in which every TOU period must break even on its own, involves larger price differentials between the periods than TOUA, which maintains the actual price ratios between periods that are currently in use for most of these customers. Starting from flat rates, TOUB causes most of the transfers that would result from RTP. In aggregate, TOUB results in $91 million in transfers among these customers, 74% of the transfers that would result from full RTP. TOUA prices vary less and, as a result cause smaller transfers compared to flat rates. The $54 million in transfers under TOUA in scenario I are 44% of the level that would result from full RTP.

The bottom panel of table 2 presents the transfers that would result from switching from TOUA to RTP for these customers. From a political economy viewpoint, this may be the more relevant comparison, because TOUA most closely reflects the current billing arrangement for these customers. Under scenario I, the aggregate transfers are 37% smaller with this switch than under a flat-rate to RTP switch.

Under wholesale price scenario II, the story is very much the same, except the effect of TOU prices is more like RTP, because RTP prices don't have as extreme price spikes under scenario II as under scenario I. With scenario II, both TOUB and TOUA result in transfers that are a higher proportion of RTP transfers (83% and 53%, respectively) than occurs in scenario I. Under scenario II, the aggregate transfers are 47% smaller with a TOUA to RTP switch than with a flat-rate to RTP switch.

The results of using TOUA under the scenario III, the actual wholesale prices, is odd because the inter-period price differences maintained under TOUA are actually larger than the ratio that would result from each TOU period breaking even. This effect is so strong that TOUA prices would cause larger transfers than would have occured under RTP with the same wholesale prices. Still, transfers under scenario III are comparatively small under all three alternative pricing regimes, because the wholesale prices exhibit so little volatility.

V. Transfers from RTP Adoption if Customers Respond to Price Volatility

The calculations in the previous section assumed that the observed customers would not change their consumption in response to changes in retail electricity prices. The results highlight how, apart from any response of the RTP customers, the volatility of wholesale prices will affect the size of the transfers. Of course, the whole point of RTP is for customers to respond and, by doing so, to increase the efficiency of the entire electricity system. In other work, I have examined the systemwide efficiency of such consumption changes. Here, I examine the effect of price response just on the surplus that these customers would receive, and in particular whether the gains from price response would substantially lessen the losses that some customers would otherwise incur with a switch to RTP.[10]

In order to analyze the benefits or losses to customers when they exhibit price elasticity, it is necessary to analyze consumer surplus instead of simply the total payments by customers. Total payments would fail to capture the benefits to consumers when they increase consumption during low-price hours and would misstate the losses when a customer reduces its bill by lowering consumption during high price periods, but also loses the value of that consumption.

The consumption actually observed for these customers occured when they were facing a billing regime that most closely resembled TOUA, so I use that as the baseline from which changes in consumer surplus are measured. I then consider possible changes from the observed consumption under alternative assumptions about the customer's price elasticity of demand.

---

[10] For comparability to the results of the previous section, I use the same distribution of wholesale prices as before. Implicitly, I am assuming that adoption of RTP by the customers in this sample would not change the distribution of wholesale prices. I do this in order to maintain the clear distinction between wealth transfer effects caused by the distribution of wholesale prices that is exogenous to any one customer and the mitigation of the effect that is possible through the customer responding to those wholesale prices. In aggregate, the assumption is unlikely to hold; increasing the share of customers on RTP would dampen price volatility. The way to incorporate this effect to analyze the wealth effect on any one customer moving to RTP would be simply to assume a more elastic aggregate demand, and thus a less volatile wholesale price series, whether or not the observed customer were to switch.

Table 3: Distributions of Change in Customer Consumer Surplus
as a Result of Switching from TOUA to RTP Tariff
(636 Customers)

Assumed Customer Elasticity	PERCENTILES 1st	5th	10th	25th	50th	75th	90th	95th	99th	Share of Customers with $\Delta CS > 0$
Scenario I: Very Volatile Simulated Wholesale Prices										
$\epsilon = 0$	-50%	-14%	-9%	-5%	-2%	2%	7%	9%	12%	35%
$\epsilon = -0.025$	-47%	-12%	-8%	-4%	-1%	2%	7%	10%	12%	42%
$\epsilon = -0.1$	-37%	-9%	-5%	-2%	1%	4%	8%	10%	12%	62%
$\epsilon = -0.3$	-20%	-2%	1%	3%	5%	6%	9%	11%	13%	93%
Scenario II: Less Volatile Simulated Wholesale Prices										
$\epsilon = 0$	-22%	-10%	-7%	-4%	-2%	1%	4%	6%	9%	33%
$\epsilon = -0.025$	-22%	-10%	-7%	-4%	-2%	1%	4%	6%	9%	36%
$\epsilon = -0.1$	-20%	-9%	-6%	-3%	-1%	1%	4%	7%	9%	41%
$\epsilon = -0.3$	-17%	-6%	-4%	-1%	1%	3%	5%	7%	10%	62%

To be concrete, I assume that customer i has a constant elasticity of demand in hour h, $q_{hi} = A_{hi} \cdot P_h^{\epsilon}$. I assume a certain elasticity, ϵ, and can then derive A_{hi} for each customer-hour based on the assumption that q_{hi} is its observed consumption and P_h is the TOUA price for that hour. The customer's change in consumer surplus from facing an RTP price in hour h rather than the TOUA price for that hour would then be:

$$\Delta CS_{hi} = \frac{A_{hi}}{(\epsilon+1)} \cdot (P_{TOUA}^{\epsilon+1} - P_{RTP}^{\epsilon+1}) \qquad [1]$$

Aggregating the result of [1] over all hours for a customer allows me to calculate its change in consumer surplus. As a basis for comparison, I then divide the customer's change in consumer surplus by its total bill under TOUA pricing and observed consumption.

The distributions of the results are presented in table 3. I show results for only scenarios I and II.[11] The first row in each scenario section indicates the distribution of percentage change with no customer price response. This row just matches the bottom panel of table 2 except with a reversal of the sign because I am now considering the change in consumer surplus rather than expense.

[11] Under scenario III, as shown earlier, TOUA prices vary more on average across TOU periods than RTP prices, so the transfers from changing to RTP are a result of *reduced* volatility with RTP.

The remaining three rows in each section present the distribution of change in consumer surplus with varying levels of assumed price elasticity of demand on the part of the observed customers. Unlike the results with zero elasticity from these customers, with price responsiveness, the aggregate consumer surplus change over all customers is not zero. By revealed preference, each customer is at least as well off as if it exhibited no price response. Thus, with price response, the *aggregate* change in consumer surplus is positive for this class of customers.

The results presented in table 3 indicate that while price responsiveness will mitigate to some extent the losses of customers with costly demand profiles, it may not substantially change the political economy of the issue. Modest price elasticity does not have as large an effect as one might hope on a customer's net gain from RTP. For instance, under wholesale price scenario I, with no price responsiveness, a customer at the 10th percentile of the distribution sees a consumer surplus loss of 9% of its TOUA bill. But even if customers have a -0.1 price elasticity in response to RTP price variation, the customer at the 10th percentile still sees a loss of 5% of its TOUA bill. Looking across table 3, it is clear that an elasticity of -0.1 moves the distribution of gains/losses in the positive direction, but by only a few percentage points or less.

The right-hand column of table 3 indicates the share of customers who benefit from a switch to RTP under the assumed level of customer price elasticity, and continuing to take the wholesale price distribution as exogenous. With no customer price elasticity, about one-third of customers would gain consumer surplus as a result of switching from a TOUA retail tariff to RTP. Demand elasticity increases this number and shifts the distribution, but even if these customers have an elasticity of -0.1, there are many customers who are still worse off.[12] Only with a much higher elasticity, which seems unlikely in the short run, are a large majority of these customers likely to benefit from a switch to RTP.

Demand elasticity has a greater effect on customer gains in scenario I, in which wholesale prices are very spiky, than under scenario II, which has more moderate spikes. This reflects the fact that the surplus gain from elasticity is larger when prices are more volatile.[13]

---

[12] The magnitudes of these aggregate consumer gains are consistent with the effects that Borenstein (2005a) and Holland and Mansur (2005) find.

[13] Borenstein and Holland (forthcoming) make this point in evaluating the gains for an individual

Unfortunately, many customers still have a very negative view price of volatility, seeing it as introducing detrimental risk into the firm's operations. In ongoing research with these same data, I am investigating the potential for mitigating that risk using straightforward hedging instruments.

VI. Two-Part RTP Programs Lessen the Wealth Tranfers from RTP Adoption

The analysis suggests that adoption of real-time pricing may be difficult without some supplemental program that compensates the customers who are made worse off by the change. Georgia Power, which runs the oldest RTP program in the U.S., has mitigated the lost cross-subsidy effect by allowing customers to lock in a certain baseline level of consumption at the regulated TOU rate and pay RTP only for deviations from their baseline level of consumption. Such "two-part" RTP pricing programs are often touted for their risk mitigation effect, but they can also maintain the cross-subsidy and thus potentially reduce political opposition to RTP.[14]

The way in which such two-part RTP programs allow maintenance of the pre-RTP cross-subsidy may not be obvious at first. In a TOU program, if the retail price of power during each TOU period is set equal to the true cost for power during that period, then how could a customer be cross-subsidized by being allowed to purchase at that price? The answer is two-fold.

First, TOU prices frequently do not actually reflect the true peak/off-peak difference in wholesale costs, instead underpricing the peak period and overpricing the offpeak period. In such case, assigning a customer baseline (CBL) level for TOU-rate purchases based on the customer's past levels of consumptions during each TOU period maintains the average cross-subsidy that the customer received under the pre-RTP plan due to the cross-subsidy *between* TOU periods. Those with disproportionate consumption during the designated peak period will continue to benefit from the fact that they consume disproportionately at times when the retail price of the energy is on average below the wholesale cost.

A second, closely related effect is somewhat more subtle: there is a *within* TOU

customer that moves to RTP.

[14] See Barbose, Goldman and Neenan (2004) for a broad survey of RTP programs with alternative baseline approaches.

period cross-subsidy that is usually maintained. If under two-part RTP a customer is permitted to buy a baseline demand pattern within a TOU period that is more costly than the retail provider's average acquisition cost for power it buys during that TOU period as a whole, then the customer will continue to be cross subsidized. For example, consider a summer peak TOU period that covers noon-6pm for all non-holiday weekdays during June, July, August and September. Assume that the TOU price is set by the reatil provider to cover the expected wholesale cost of the power acquisition it needs to make during that period, so there is no cross subsidy between TOU periods. Consider a customer that has disproprotionately high demand (compared to the retail provider's load) during August peak periods, which happen to be when wholesale prices are highest in the summer. Under a TOU program, that customer is cross-subsidized because *within* the summer peak TOU period it is buying a disproportionate quantity of power during the most expensive wholesale price hours.

This within-TOU-period subsidy could continue or be eliminated under a two-part RTP program depending on the way in which the CBL quantity – the quantity the customer is allowed to purchase at the TOU rate – is determined. If the CBL quantity is proportional in each hour to the retail provider's aggregate load, then all customers are buying the same standardized product (though differing amounts of it) at a cost-based price and there is no within-period cross-subsidy. On the other hand, if each customer is allowed to customized its baseline quantity purchased across the hours that are within the peak TOU period – the most common system being a baseline determined by the customer's own consumption in past years on the equivalent dates – then some customers will purchase more quantity during the most expensive hours. If those customers are still allowed to buy that quantity at the standard TOU rate – as is the case in most programs – then the cross-subsidy will be maintained. In practice, nearly all CBLs have customized the demand pattern of each customer's baseline consumption to reflect the customer's past consumption, thus maintaining a significant cross-subsidy.

Two-part RTP programs can in fact be designed to eliminate all cross-subsidy in energy costs. This can be done while still allowing customers to pre-purchase fixed quantities of power in order to reducing the risk of volatile power bills, an effect that is completely distinct from the impact on transfers. It is simple to describe two such proposals that happen to represent opposite extremes of flexibility.

The first, as suggested above, would offer a standard product within each TOU period that is a fixed-proportion in each hour of the retail provider's expected aggregate load. The retail provider would price this at the expected cost of the "load slice." No "cherry picking" of the most expensive hours would be possible, because the only product available would be a fixed proportion of aggregate demand in all hours. So, no cross-subsidy would result.

An alternative proposal offers complete flexibility, but sets separate prices for each hour. Under this proposal, the retail provider would set a forward price for each hour of the coming year based on its best forecast of wholesale price (through an analysis of expected demand and supply drivers). The retail provider would price each hour so that there is no expected cross-subsidy across hours. A customer would then be allowed to craft its own baseline quantity, potentially buying forward a different quantity for each hour of the year.[15]

Each of these two proposals permits the risk management function that is often suggested as the basis for two-part RTP programs while eliminating the cross-subsidies the exist under the pre-RTP system. Yet, neither of these programs has been adopted anywhere in the U.S. Instead, customized baselines have been used or baselines purchases have simply been made available at prices below the expected wholesale costs. This suggests that the designs of the customer baseline programs have been aimed at mitigating the loss of cross-subsidy as well as reducing the perceived bill risk associated with RTP.

Finally, note that not even the most sophisticated two-part RTP program is unlikely to completely eliminate wealth transfers that would result from RTP adoption. Even if every customer were required to pre-purchase their expected hour-by-hour demand at the regulated TOU rates, the stochastic components in consumption and real-time wholesale prices would cause some transfers. On the unexpectedly hot summer day, prices would rise and those customers who see the greatest increase in their consumption above their expected level would be hurt the most. Thus, those customers whose demand experiences unanticipated shocks that are most strongly postively correlated with shocks to system demand and price would still take a wealth hit. This would be the case even under a two-part RTP program in which each customer buys in advance their customized expected demand quantity for each hour.

[15] Borenstein (2005b) describes this proposal in greater detail.

In ongoing research, I am studying the empirical magnitude of the wealth transfer mitigation that result from various forms of two-part RTP programs.

VII. Conclusions

Introducing real-time electricity pricing is likely to harm some customers by removing the existing cross-subsidies to customers that consume disproportionately more when wholesale prices are highest. Those customers are likely to oppose RTP initiatives if their potential loss is substantial and there is no supplemental program to offset their loss. Using data on a sample of 636 industrial and commercial customers in southern California, I've shown that implementing RTP results in significant transfers compared to a flat-rate tariff. Half or more of these transfers, however, occur with just a change from flat-rate to time-of-use pricing, a change that has already taken place for the customers in this sample, and for most large industrial and commercial customers in the U.S. Still, current TOU tariffs probably understate the long-run equilibrium cost differential between peak and off-peak periods, thus reducing the transfer caused by such rates and increasing the additional transfer that would result from moving to full RTP.

One hope for broader RTP support is that customers may help themselves under RTP by reducing consumption when prices are high and consuming more when prices are low. While this price responsiveness generates substantial efficiencies in aggregate (as shown by Borenstein (2005a)), I demonstrate that it is unlikely to be large enough for most customers with costly demand patterns to overcome their lost cross-subsidy. Even if customers exhibit real-time price elasticities of -0.1, I conclude that a large share of them would still be losers under RTP.

The analysis makes clear that in the political economy of retail electricity pricing there is likely to be a role for programs that mitigate the wealth transfers from RTP adoption while still achieving the efficiency gains. I've shown that "two-part" RTP programs, which allow customers to buy a baseline quantity at a regulated rate, fulfill this function under their typical implementation.

REFERENCES

Barbose, Galen, Charles Goldman and Bernie Neenan. "A Survey of Utility Experience with Real-Time Pricing," Lawrence Berkeley National Laboratory Working Paper No. LBNL-54238, December 2004. Available at http://eetd.lbl.gov/ea/ems/reports/54238.pdf.

Borenstein, Severin. "The Long-Run Efficiency of Real-Time Electricity Pricing," Energy Journal, 26(3), 2005(a).

Borenstein, Severin. "Time-Varying Retail Electricity Prices: Theory and Practice," in Griffin and Puller, eds., *Electricity Deregulation: Choices and Challenges*, Chicago: University of Chicago Press, 2005(b).

Borenstein, Severin and Stephen P. Holland. "On the Efficiency of Competitive Electricity Markets With Time-Invariant Retail Prices," *RAND Journal of Economics*, forthcoming.

Holland, Stephen P. and Erin T. Mansur. "The Distributional and Environmental Effects of Time-Varying Prices in Competitive Electricity Markets" Center for the Study of Energy Markets Working Paper #143, University of California Energy Institute, May 2005. Available at http://www.ucei.org.

PJM Interconnection Market Monitoring Unit. "2004 State of the Market Report," March 2005. Available at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf.