THE POWER OF DYNAMIC PRICING

Ahmad Faruqui, Ryan Hledik, and John Tsoukalis

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As the Smart Grid takes shape, it opens new vistas for change. One of those salient opportunities for change that is enabled by the Smart Grid is the pricing of electricity. By and large, existing rate designs hide the temporal variation in the cost of electricity and thereby promote over-consumption of electricity during peak times and under-consumption during off-peak times. In much of North America, the problem is especially pronounced during the top 60-100 hours of the year which may account for as much as 10-18 percent of system peak load. In order to meet this critical peak load, expensive combustion turbines are purchased and installed, raising rates for all customers.

Dynamic pricing rate designs can remedy this problem and enhance economic efficiency. For that reason, they are receiving increased attention by state commissions throughout the country. California has made a major commitment to it, by approving the deploying of advanced metering infrastructure (AMI) and by establishing critical-peak pricing (CPP) rates as the default tariff for all non-residential customer classes with AMI.[2] Other smart rate designs, such as real-time pricing, may be provided as options.

To show the power of dynamic pricing, we develop a set of illustrative rates using data from a generic California utility and compute the benefits that would accrue to the state's economy from widespread deployment of these rates. While the numbers are specific to California, the process and methodology are perfectly general and should be of interest to utilities and regulatory bodies throughout North America.

We develop dynamic pricing rates for four customer classes: Residential, Medium Commercial and Industrial (C&I), Large Commercial, and Large Industrial. In order to show the development of these rates, we begin with a discussion of existing rates. All the dynamic pricing rates are developed to be revenue neutral to these existing rates.

Existing Rates

The Domestic Non-CARE Five Tiered rate was used as the representative rate for residential customers in California. This rate design features an inverted block rate structure, meaning that the customer's rate progressively increases (in steps) as their consumption within a month increases.

The generation component of the rate starts at \$0.045/kWh for consumption below the customer's "baseline" amount. This baseline amount varies across the various climate zones in California. Once a customer's consumption exceeds their baseline, they are subject to a rate of \$0.065/kWh until they reach 130% of the baseline. The rate continues to increase as consumption increases. Consumption up to 200% of the baseline is charged at \$0.151/kWh, up to 300% of the baseline is charged \$0.186/kWh, and any consumption above 300% of the baseline is charged at a rate of \$0.221/kWh. For the average residential customer, this averages to a generation rate of \$0.092/kWh. When this generation component is added to the average delivery charge of $0.072/kWh and the Basic Charge of $0.020/day, the average all-in summer electricity rate totals to $0.165/kWh.

Rate design for commercial and industrial customers is more complicated due to the presence of demand charges. The representative rate for Medium C&I customers contains two such demand charges. For every kilowatt of summer peak load, customers are charged a Facilities Demand Charge of $8.60/kW and a Summer Demand Charge of $18.79/kW. On top of these demand charges, they are charged a flat rate of $0.072/kWh for energy and a $0.015/kWh delivery charge. A customer charge of $85.75/month and a Single Phase Service rebate of -$26.65/month are also applied. Based on the average load profile for a Medium C&I customer (38.4 kW of demand and 66,818 kWh of energy consumption during the summer) the average all-in summer electricity rate totals to $0.153/kWh.

Large commercial customers are represented by a time-of-use (TOU) rate that divides the day into three pricing periods: peak, mid-peak, and off-peak. Customers are charged a different rate for the energy they consume in each of these periods. During the peak period the energy charge is $0.099/kWh, during the mid-peak period it is $0.078/kWh, and in the off-peak period it is $0.050/kWh. The rate also includes demand charges. There is a year round Facilities Charge of $9.71/kW and also a two-tiered summer demand charge. The tier which corresponds to the peak period is $12.33/kW, and the tier that corresponds to the mid-peak period is $4.25/kW. When these are coupled with a delivery charge of $0.014/kWh and a customer charge of $414.98/month, the average all-in summer electricity rate for this class is $0.132/kWh.

Large industrial customers have a rate schedule which is similar to that used to represent large commercial customers. The three-part energy charge is as follows: $0.077/kWh in the peak period, $0.061/kWh in the mid peak period, and $0.039 in the off peak period. The year-round Facilities Charge is $2.48/kW, the summer peak charge is $12.33/kW, and the summer mid-peak charge is $4.25/kW. The delivery charge is $0.013/kWh and the customer charge is $2,199/month. Together these charges total an all-in summer electricity rate of $0.092/kWh.

Developing the Critical-Peak Price with Time-of-Use Rate (CPP/TOU)

The CPP/TOU rate layers a CPP rate on top of a TOU. The layered rate means that customers pay a critical rate during peak hours on the few days of the summer when wholesale prices are the highest. During other peak days, the CPP/TOU rate operates like a TOU rate. During peak hours customers will pay a peak rate that is higher then the existing all-in rate. During all other hours, customers have an off-peak rate that is lower than the existing rate. Thus, the CPP/TOU rate is designed to convey the true cost of power generation to electricity customers and to provide them with a price signal that more accurately reflects variation in energy costs over the course of the day. This time-varying rate structure provides customers with an opportunity to reduce electricity bills through reductions in peak period consumption.

Figure 1 illustrates the difference between the CPP/TOU rate structure on a critical day and a peak day. For the Large Commercial and Industrial rate classes, an additional price level, called the mid-peak period, was added to the CPP/TOU rate. This is consistent with the existing structure of Large Commercial and Industrial rates.

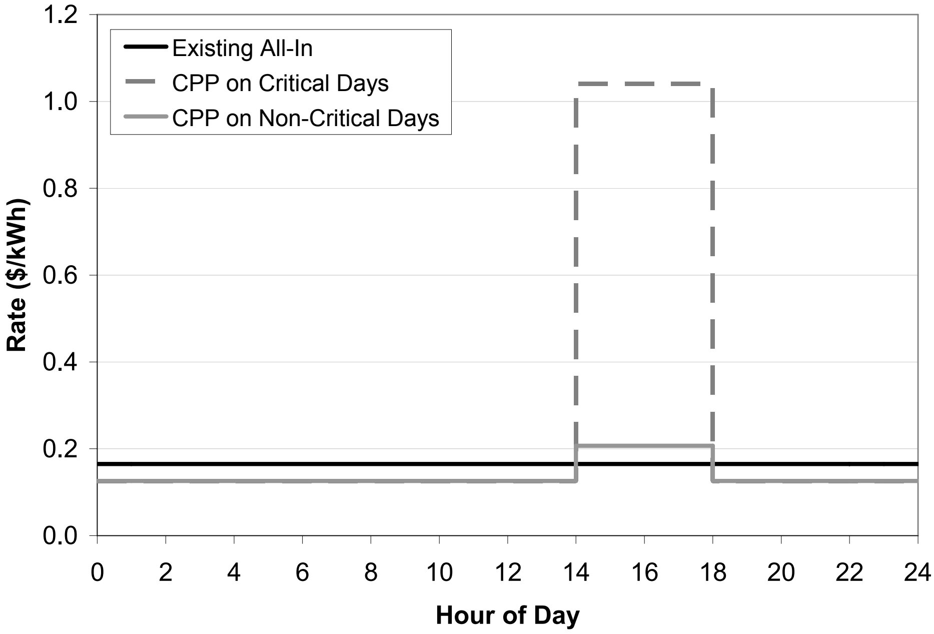

Figure 1: Illustrative CPP/TOU Rate

The critical-peak rate is dispatched during the 15 "critical" days of the summer when market prices are anticipated to be at their highest. For the purposes of this study, the summer period was defined as June through September. The critical rate would be in effect during the hours from 2 pm to 6 pm on these critical days. Customers are notified the day before a critical day will be taking place.

An important input in calculating the CPP/TOU rate is the price of capacity. We have assumed a capacity price of $75/kW-year, which is based on the cost of a new combustion turbine in California. To calculate the residential critical-peak rate, the capacity price was de-rated by 30% to account for the uncertainty associated with two factors: that the critical-peak rate may not be dispatched at the right time and that the rate would be available whenever needed. This de-rate also nets out the revenues that would be realized by the hypothetical combustion turbine in the energy market. In other words, once the de-rate is applied, the new cost estimate represents the fixed payment that the owner of the combustion turbine would need to be made whole financially. The de-rated capacity cost is divided by 60, the number of critical hours in the summer, and then is added to the existing all-in rate to produce the all-in critical rate. For residential customers the critical peak rate equals $1.04/kWh. The residential off peak rate was designed to roughly approximate the utility's marginal energy costs during off peak hours. This was estimated to be $0.0126/kWh. The peak rate was then solved to maintain revenue neutrality using the utility's average load profile. Table 1 displays the final CPP/TOU rate structure for all four customer classes.

Table 1: CPP/TOU All-In Rates (cents/kWh)

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	13.2	9.2
Critical Peak Rate	104.0	98.5	101.2	99.1
Peak Rate	20.7	32.1	19.7	14.6
Mid-Peak	N/A	N/A	11.1	7.8
Off Peak Rate	12.6	10.0	8.3	5.6

The methodology for calculating the CPP/TOU for Medium C&I customers varied slightly from the residential CPP/TOU due to the presence of demand charges in the existing rates. The critical rate was set by adding the de-rated capacity price to the energy component of the existing rate. It was assumed that this critical peak rate replaced the generation-related demand charge in the existing tariff. The off peak rate was set equal to an approximation of the off peak marginal energy cost, and the peak rate was solved for revenue neutrality. Ultimately, the new CPP/TOU rate for medium C&I customers no longer had a separate generation demand charge due to the assumption that this cost was recovered through the critical peak rate.

The CPP/TOU rates for large commercial and industrial customers have four rate levels. Like the existing TOU rate structures, the new dynamic CPP rates have an additional mid peak level. The mid peak period runs from 7 am to 2 pm and from 6 pm to 11 pm on every weekday. The critical rate was calculated with the same methodology described for medium C&I customers. Both the off peak rate and the mid peak rates were set equal to the off peak and mid peak energy components of the existing TOU rate. Then, the peak rate was solved for revenue neutrality based on the load profiles for Large Commercial and Industrial customers.

Time-of-Use Rates (TOU)

The TOU rate divides the day into two or more time periods, with a different rate for each period. For example, a peak period might be defined as the period from 12 pm to 6 pm on weekdays, with the remaining hours being considered off-peak. The rate would be higher during the peak period and lower during the off-peak, mirroring the variation in the cost of supplying electricity during those time periods. With the TOU, there would be no uncertainty as to what the rates would be and when they would occur. In other words, the TOU rate is not "dispatchable," and would not technically be considered a "dynamic" rate according to many definitions. Figure 2 compares the TOU rate to a flat rate on a weekday.

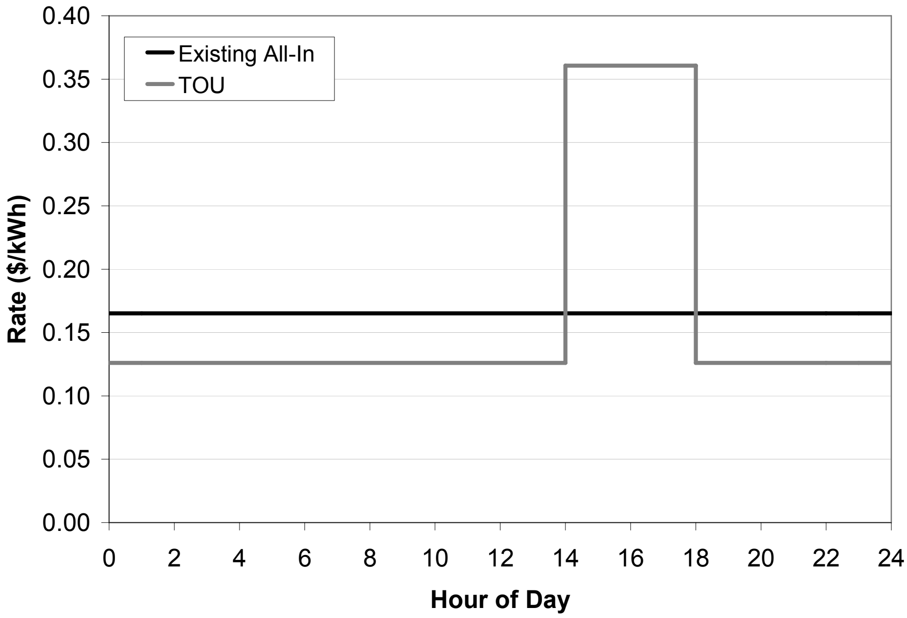

Figure 2: Illustrative TOU Rate

A TOU rate was designed for the Residential customer class and for the Medium C&I customer class. The TOU was designed to apply only to the summer period from June through September, and the peak period was defined as 2 pm to 6 pm on every weekday.

The first step in designing the Residential rate was to set the off peak energy rate to $0.126/kWh, the same estimate of off peak marginal energy costs that was assumed in calculating the CPP/TOU rate. The peak rate was then solved to be revenue neutral to the existing rate using the average Residential customer's load profile. The Medium C&I TOU was created in a similar manner. The off peak rate was set equal to the assumed marginal energy cost for that period, with a slight discount to ultimately produce a significant peak-to-off-peak differential. Then, the peak rate was solved for revenue neutrality. It was assumed that the generation demand charge would be recovered through the peak rate in the revenue neutrality calculation. As a result, the Medium C&I TOU rate does not additionally include a generation demand charge. Table 2 outlines the TOU rate structures created for Residential and Medium C&I customers.

Table 2: Time-of-Use All-In Rates

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	N/A	N/A
Peak Rate	36.1	31.0	N/A	N/A
Off Peak Rate	12.6	10.0	N/A	N/A

Peak-Time Rebate (PTR)

Because of the presence of Assembly Bill 1X, which prevents CPP rates from being offered to residential customers, the utilities in California have proposed deployment of peak-time rebate (PTR) as the dynamic rate for the residential customer class. Rather than charging a higher rate during critical events, the PTR gives customers the opportunity to buy through at the existing rate. However, customers have an incentive for reducing critical-peak usage in the form of a rebate that for each kilowatt-hour of load reduction that is provided during the critical period. Figure 3 illustrates the PTR rate on a critical day. It is important to note that this rate structure requires the establishment of a baseline load for each individual customer, from which the reductions can be computed.

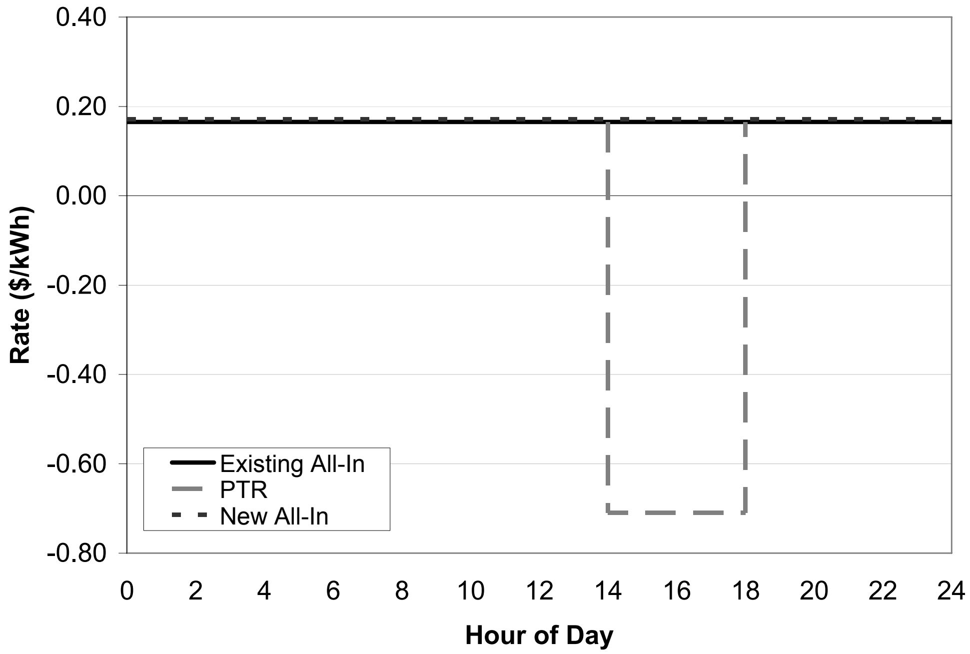

Figure 3: Illustrative PTR Rate

While all forms of dynamic pricing are designed to provide customers with the opportunity to save on their electric bill, the PTR provides a level of bill protection that is not embedded in these other rates. Because it provides a rebate during critical events but does not increase the rate during other hours, in the short run a customer's bill can only decrease under the PTR. However, payment of the rebates will result in an increase in the utility's revenue requirement and, as a result, an increase in the electricity rate in the future. It is estimated that this increase would be equal to 1.5% of the existing all in rate. This has been illustrated in Figure 5 and is shown below as an increase in the existing rate from $0.165/kWh to $0.168/kWh.

Table 3: **Peak Time Rebate All-In Rates and Peak Rebate**

	Residential	Medium C&I	Large Industrial	Large Commercial
Existing All-In Rate (Summer)	0.165	N/A	N/A	N/A
New All-In Rate	0.168	N/A	N/A	N/A
Peak Rebate	-0.875	N/A	N/A	N/A
Off Peak Change	0.000	N/A	N/A	N/A

For this analysis, a PTR rate was developed for Residential customers as this is the only rate class that is likely to be offered a PTR in California. The rebate given for demand response during critical hours is determined using the critical peak rate in the residential CPP/TOU. The rebate is simply the existing all-in rate subtracted from the critical rate. The CPP/TOU critical rate was calculated to be $1.04/kWh and the all in rate was $0.165/kWh. Therefore the peak rebate is $0.875 for each kilowatt-hour of demand response.

Real Time Pricing (RTP)

Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Participants are made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers (generally above one megawatt of load) face hour-ahead prices. These rates include prices that reflect the cost of producing electricity at the most granular level of all rates considered in this whitepaper.

RTP programs are generally only offered to Large C&I customers with the exception of Illinois, where two utilities currently offer them to their residential customers. Figure 4 shows how the price for electricity under an RTP program could compare to a flat rate on a peak summer day.

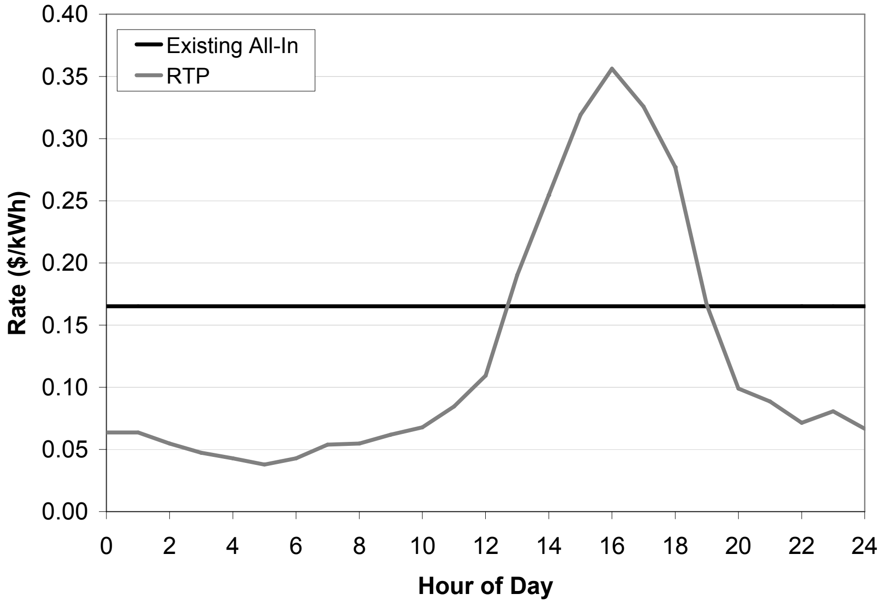

Figure 4: Illustration of RTP Rate

In contrast to the other rates in this paper, the RTP rate was designed to be in effect for the entire year, not just the summer. To create this year-round rate with hourly variability, California PX wholesale market prices for SP15 and the year 1999 were utilized. These prices were used as the basis for the price shape, because they represented the best approximation of a time period for which there was robust California electricity market price data with somewhat normal market conditions. The post-1999 market data has was heavily influenced by market manipulation and other anti-competitive behavior, and market simulations did not produce the hourly variation in prices normally seen in electricity markets. Today's California ISO real-time electricity market is fairly illiquid and includes price patterns that are not truly representative of marginal energy costs.

The first step in creating the RTP rate was to scale the historical hourly market prices to today's energy costs. This was done in such a way that the scaled price series would equal the generation rate for each customer class. The scaling factors that were used to make this adjustment to the market prices are presented in the second row of Table 6.

Table 4: Range of Prices under RTP

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Year-round)	16.3	12.1	11.5	7.6
Scaling Factor	3.1	2.4	2.4	1.9
Max Hourly Price (cents/kWh)	69.4	54.0	55.4	43.3
Simple Average Price (cents/kWh)	8.2	6.4	6.5	5.1
75th Percentile Price (cents/kWh)	9.8	7.6	7.8	6.1
25th Percentile Price (cents/kWh)	5.8	4.5	4.6	3.6

The next step was to allocate capacity costs. The approach that was taken in this study was to allocate the costs equally across hours. An alternative approach for allocating capacity costs that would send a stronger price signal to customers is described later in this section. The remaining components of the existing tariff are applied under the new rate just as they are under the existing tariff. Table 6 quantifies the hourly variability in the final RTP rates.

For residential customers, the maximum hourly price reaches \$0.694/kWh under the RTP rate. This is not as high as the critical rate under CPP/TOU but it is well above the existing rate. The majority of hours under the RTP rate design have prices well under the existing rate. The 75th percentile price for residential customers is \$0.098/kWh, which is already below the existing rate of \$0.163/kWh. Similar patterns are seen for the other customer classes.

An Alternative Approach to RTP Rate Design

The RTP rate that was described previously allocates the cost of capacity across all hours. An alternative approach could be to allocate this cost only to the critical peak hours, using a methodology similar to that used to develop the CPP/TOU rate. This would send a stronger price signal to customers and, as a result, encourage greater demand response at times when it is needed most. The extent to which hourly electricity prices do not reflect this capacity cost may also be a more equitable means of allocating the costs.

This alternative RTP design is referred to in this study as the Peak RTP. An illustration of how this rate would differ from the other RTP rate design (referred to hereafter as the “Smooth RTP”) is shown in Figure 5.

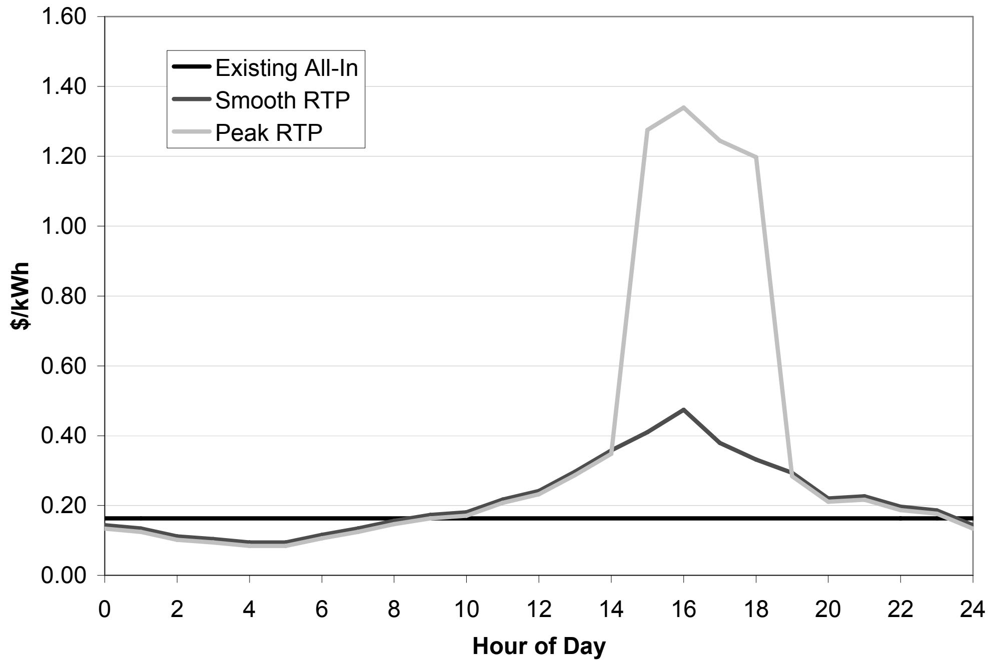

Figure 5: Comparison of Peak RTP to Smooth RTP on Critical Day

The Peak RTP rate is significantly higher than the Smooth RTP during critical hours, but presents an off peak discount during all other hours of the year. This would provide customers with opportunities for larger bill savings and, thus, a greater incentive to shift load away from the critical peak periods.

The Potential Impact of Dynamic Pricing

The illustrative rates described in the previous section have the potential to meet the four ratemaking objectives identified in a recent whitepaper: economic efficiency, equity, choice, and simplicity.[3] However, it is difficult to know exactly how well these rates will perform under these criteria since they have not been offered to California's customers. Regardless, the impacts of the rates can be simulated using the best available data to develop a deeper understanding of the relative magnitude of the benefits that each rate may provide. In this section the results of such simulations are summarized. Specifically, the simulations produced estimates of impacts on peak demand and monthly bills at the individual customer level. These impacts were developed for a distribution of customers and multiplied into system-level data to arrive at projections of the impacts on the California economy in terms of overall peak demand reduction and the change in the total resource cost.

The approach employed to assess load response is driven by a modeling system called The PRISM (Pricing Impact Simulation Model) Suite. PRISM was developed during the California Statewide Pricing Pilot (SPP), a large-scale experiment carried out jointly by the three investor-owned utilities in the state and the two regulatory commissions to assess customer response to dynamic (time-based) rates.[4] This pilot was the largest experimental pilot of its kind, and formed the basis for the AMI business cases that have been filed by all three of the California IOUs with the California Public Utilities Commission.

The purpose of the SPP was to measure the change in consumption patterns that customers would exhibit when the structure of their rate was changed from a non-time varying rate to one that was time varying and dynamic, such as a CPP. The experiment involved over 2,500 residential and small commercial and industrial customers and spanned a period of more than two years. Ultimately, the SPP produced estimates of customer response to dynamic rates. These estimates varied not only with the dynamic rate design (i.e. price level during the critical peak and off peak periods) but also with information about the region's average load profile, weather, and CAC saturation.

The PRISM Suite of Models[5]

For this study, the PRISM model was calibrated to the utility's system characteristics, such as weather conditions, load profiles, saturation of central air conditioning ("CAC"), and existing rates. When combined with a forecast of the number of customers participating in the rate, the result was a system-wide forecast of annual peak demand reductions. The peak demand reductions are expected to yield supply-side benefits, such as lower capacity and energy costs, as well as other additional benefits like wholesale market price mitigation. Figure 6 summarizes this approach.

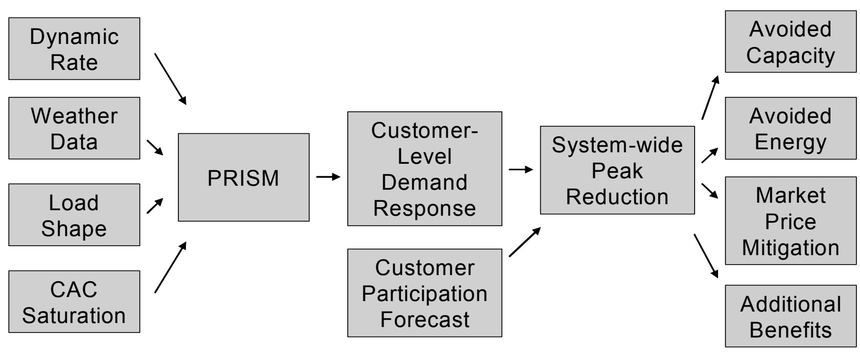

Figure 6: The PRISM Suite Process

Inputs to PRISM were developed using data representative of California's system conditions. The relevance of each PRISM input to the modeling effort is described briefly below.

- **The dynamic rate:** In order to estimate the impacts of dynamic pricing, it is necessary to model a specific rate design that would be representative of the type of dynamic rate that customers might enrolled in. The previous section outlines the rate design process for our set of dynamic rates.

- **Load shapes:** Load shapes for each class are used to determine the kilowatt-hour per hour impacts that are produced by each customer in response to the dynamic rate. In other words, PRISM produces an estimate of the percent reduction in peak demand that each customer will provide.

- **The existing tariff:** The existing rate is a necessary input to the analysis, because a customer's responsiveness to a new dynamic rate will be driven by the price increase or decrease that the CPP rate provides relative to the customer's existing rate. In other words, during the critical peak hours, a customer is responding not just to the high absolute price level of the dynamic rate, but to the relationship of that price to the existing rate. Similarly, in the off peak, the customer's response is assumed to be driven by the relative discount that he or she receives through the dynamic tariff.

- **Central Air Conditioning (CAC) saturation:** The CAC saturation of a region can influence its expected residential class peak reduction. Generally, customers with CAC have a greater ability to reduce consumption during peak times, because they can have direct control over their thermostat (and in many cases can even program the thermostat to automatically increase the temperature and thus reduce electricity consumption during the peak period of the day). Thus, all things being equal, in a region where a large percentage of customers have CAC, the expected peak demand reduction from dynamic pricing will be higher than in a region where a small percentage of customers have CAC.

- **Weather:** Temperature has also been found to be correlated with peak reductions from time-based pricing. Generally, hotter regions tend to experience greater peak reductions. Two specific temperature statistics are used as inputs to PRISM: Peak vs. off peak temperature differentials and the average daily temperature.

PRISM Elasticities

Ultimately, the demand response estimated with PRISM is driven by the model's assumed price elasticities. PRISM employs two elasticity inputs. The elasticity of substitution is designed to measure demand response caused by the price differential in two adjacent time periods. As a result, this elasticity represents the pure change in load shape (i.e. load shifting) in response to the new dynamic rate. This elasticity of substitution effect is illustrated in Figure 7.

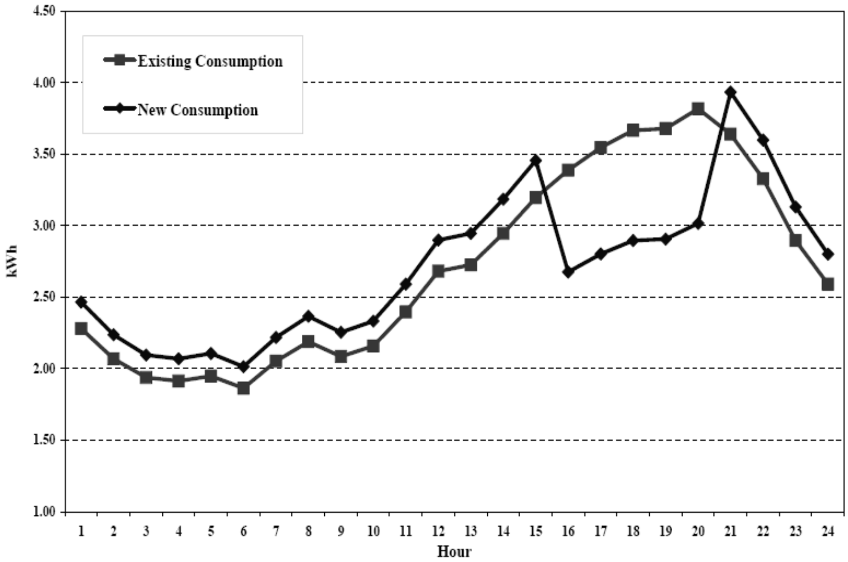

Figure 7: The Elasticity of Substitution Effect

The second elasticity embodied in PRISM is the daily price elasticity. This elasticity is applied to the difference in the average price of electricity over the course of the full day. For example, with the CPP/TOU rate, a load-weighted price for the average critical day is calculated from the critical peak rate and off peak rate. The ratio of this load weighted average price to the existing flat rate is applied to the daily price elasticity to generate the second component of the PRISM demand response estimate. The daily price elasticity effect is illustrated in Figure 8.

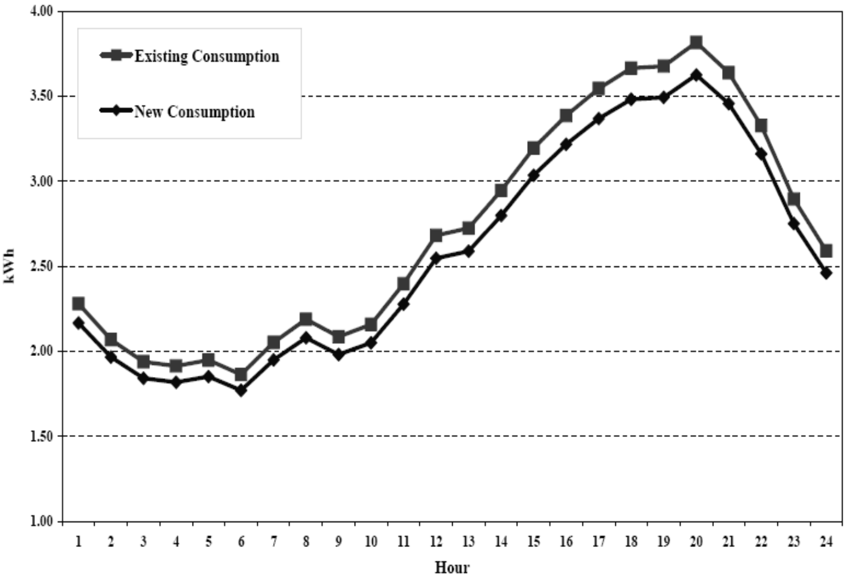

Figure 8: The Daily Price Elasticity Effect

These two demand response components are used to estimate the new usage per hour in each time period. This approach is applied to both the critical and non-critical days. Table 7 shows the elasticity assumptions used in this analysis for each customer class.

Table 5: PRISM Elasticity Assumptions

	Elasticity of Substitution	Daily Price Elasticity
Residential	-0.08	-0.04
Medium C&I	-0.05	-0.02
Large Commercial	-0.05	-0.02
Large Industrial	-0.05	-0.02

The residential elasticity assumptions shown in Table 7 are derived from the California SPP. The commercial and industrial elasticity assumptions are adapted from recent studies on the responsiveness of C&I customers. Demand response to RTP rates was simulated using a slightly different methodology. Elasticities from a recent ComEd study on residential RTP rates were used to approximate the hourly response that might be expected from customers on these rates.[6] The RTP elasticities vary depending on the time of day and expectations about day ahead wholesale market prices.[7] The elasticities range from -0.015 and -0.048.

The data on large C&I price elasticities is somewhat limited, and there is significant uncertainty surrounding those elasticities in particular. To capture this uncertainty, a range of elasticities were utilized for each customer class, representing "high" and "low" price elasticity cases. Table

6 shows the elasticity assumptions used in the high and low cases relative to the base case assumptions discussed above.

Table 6: High and Low Case Elasticities

	Large Commercial		Large Industrial	
	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
Low Case	-0.025	-0.01	-0.025	-0.01
Base Case	-0.05	-0.02	-0.05	-0.02
High Case	-0.05	-0.10	-0.10	-0.05

The low case elasticities shown above are 50 percent of the base case elasticities. The high case elasticities were based on results from recent price elasticity studies for large customers in the Northeastern United States. These elasticities could represent the potential for demand response if a dynamic rate was offered on an optional basis to these customers, with the expectation that customers with the greatest ability to shift demand would opt into a dynamic rate.

Demand Response Impacts

One of the primary outputs of the simulation was the expected peak reduction produced by the dynamic rates. This reduction will ultimately impact the system avoided cost estimation. The impacts shown in Table 7 are for the average individual customer. Changes represent the average reduction in hourly usage during the critical period. For the purposes of this study, the critical hours were identified as the peak hours on the fifteen highest-priced weekdays of the summer. These are the hours during which the CPP/TOU rate is the highest and the rebate is offered through the PTR.

Table 7: Individual Customer Critical Peak Demand Impacts

	Residential		Medium C&I		Large Commercial		Large Industrial	
	kWh/hr	%	kWh/hr	%	kWh/hr	%	kWh/hr	%
Smooth RTP	-0.06	-4.2%	-1.2	-4.0%	-24	-4.5%	-231	-4.9%
TOU	-0.10	-7.1%	-1.8	-5.9%	N/A	N/A	N/A	N/A
PTR	-0.20	-14.5%	N/A	N/A	N/A	N/A	N/A	N/A
CPP/TOU (Low)	N/A	N/A	N/A	N/A	-26	-4.8%	-255	-5.4%
CPP/TOU	-0.22	-15.8%	-3.0	-9.9%	-51	-9.5%	-533	-11.2%
CPP/TOU (High)	N/A	N/A	N/A	N/A	-77	-14.4%	-978	-20.6%
Peak RTP	-0.13	-9.6%	-3.1	-10.2%	-56	-10.4%	-577	-12.1%

The CPP/TOU rate consistently generates large demand response impacts, ranging from 9.5 percent for large commercial customers to almost 16 percent for residential customers. The PTR rate, producing a 14.5 percent reduction, also has a significant impact among residential customer class. The Smooth RTP rate produces similar results across the entire group of customer classes, ranging only from 4.0 percent in the Medium C&I class to 4.9 percent in the Large Industrial class. However, the Peak RTP rate generates large peak reductions ranging from 9.6 percent for Residential customers to 12.1 percent for Industrial customers. While these impacts are only approximations using the best available data, they represent the wide range of impacts that can be produced from the same type of rate.

The reductions in peak load described above, as well as any other changes in consumption during non-critical hours, will have an impact on customers' bills. Table 8 presents the resulting bill savings across all the rate designs and customer classes. Bill impacts generally are not large because they are being presented for the average customer. The PTR produces slightly larger bill savings than the CPP/TOU for the residential customers despite being the product of slightly smaller peak reductions, because there is no increase in the peak and critical-peak rates under the PTR – the rate only has the potential to reduce bills in the short run. The TOU rate produces smaller bill impacts that are proportionate to the smaller critical peak reduction that is achieved through the rate. Bill savings on the RTP rates vary significantly by class, with the Smooth RTP producing greater bill savings than the Peak RTP.

Table 8: Individual Customer Bill Impacts[8]

	Residential		Medium C&I		Large Commercial		Large Industrial	
	$/month	%	$/month	%	$/month	%	$/month	%
Smooth RTP	-5.47	-5.9%	-132	-7.2%	-80	-0.2%	-21,055	-8.1%
TOU	-1.69	-1.5%	-49	-1.9%	N/A	N/A	N/A	N/A
PTR	-3.09	-2.8%	N/A	N/A	N/A	N/A	N/A	N/A
CPP/TOU (Low)	N/A	N/A	N/A	N/A	-357	-0.8%	-3,240	-1.0%
CPP/TOU	-2.83	-2.6%	-57	-2.2%	-700	-1.7%	-7,348	-2.3%
CPP/TOU (High)	N/A	N/A	N/A	N/A	-950	-2.2%	-12,148	-3.6%
Peak RTP	-0.81	-0.9%	-20	-1.1%	-378	-1.1%	-3,897	-1.5%

Distribution of Bill Impacts

Thus far, the bill impacts that were reported were for the class average customer. However, customers with peakier-than-average will experience rising bills and those with flatter-than-average load shapes will experience falling bills (prior to their making any changes to their load shape). This distribution of bill impacts would potentially have implications for the rate's performance under the "equity" ratemaking criterion. To further understand this range of impacts, the distribution of bill impacts were simulated using load research data for a sample of the utility's residential customers for the TOU and CPP/TOU rates. These impacts are summarized in Figure 9.

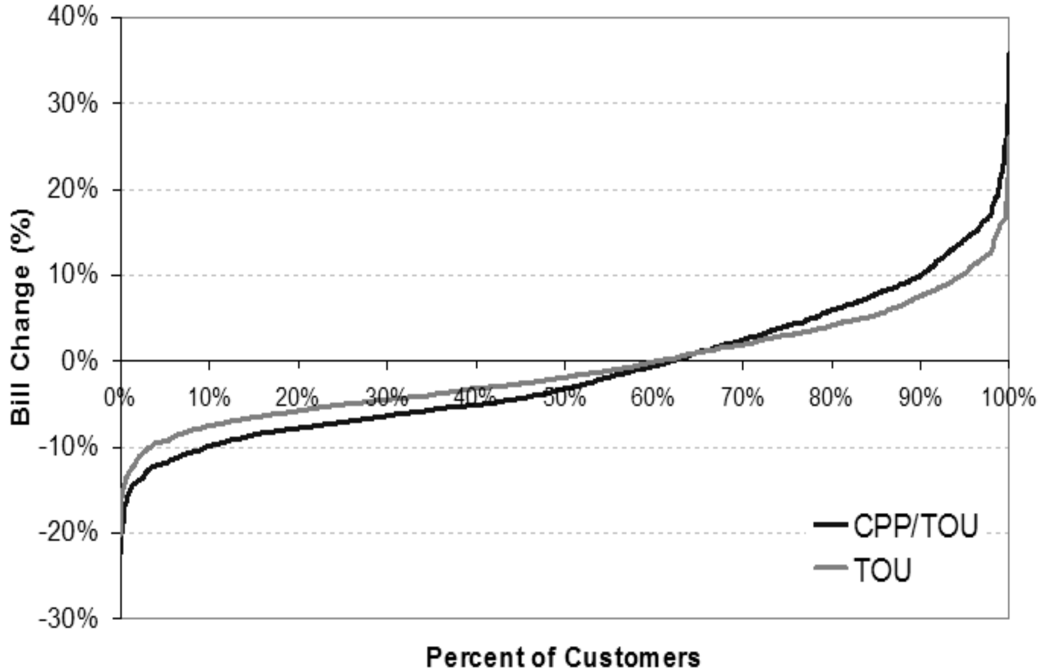

Figure 9: Distribution of Residential Bill Impacts Before DR

The impacts in this figure represent changes in customer bills relative to the existing rate *before demand response*, and thus identify the bill changes that are purely due to the structure of the new rate. Under both rates, roughly 60 percent of the customers experience bill savings. However, the CPP/TOU rate leads to larger bill increases and decreases than the TOU rate. Ultimately, for customers with very flat load shapes, bill savings could approach 20 percent. Bill impacts for customers with very peaky load shapes could potentially approach an even larger change in the absence of demand response.

After demand response, one would expect an even larger percentage of customers to achieve bill savings, as this would be the motivating reason for customers to shift load. Indeed, the percentage of customers on the CPP/TOU rate that achieve bill savings are estimated to increase from 60 percent to more than 70 percent. This is illustrated in Figure 10.

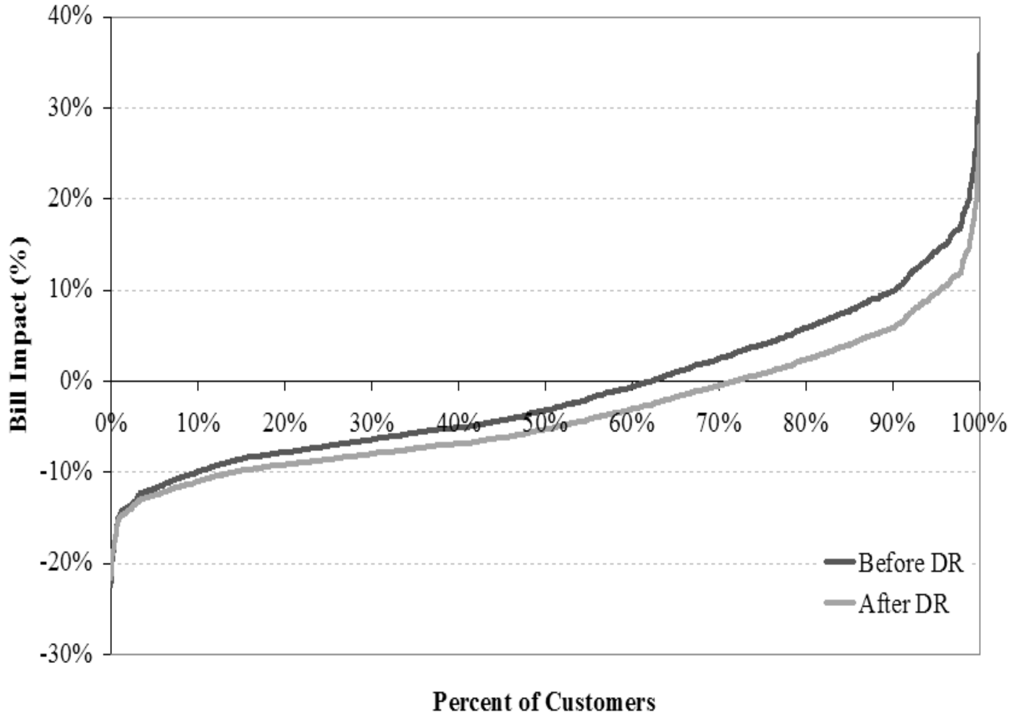

Figure 10: Distribution of Residential CPP Impacts Before and After DR

Statewide Impacts

The value of dynamic pricing to the California economy was estimated by applying the peak demand reductions described previously into a system-wide impacts model. The larger these reductions in peak demand are, the greater the potential financial benefits. The system-wide impacts model forecasts the effect of dynamic pricing over a 20 year time horizon. The three primary inputs are (1) the number of customers in each class (2) the potential avoided cost for new generation, transmission, or distribution capacity, and (3) and the potential avoided energy cost.

The system impacts model begins with the assumption that there are 9.3 million Residential electric customers in California, 225,000 Medium C&I customers, 5,000 Large Commercial customers, and 3,000 Large Industrial customers. The assumed annual customer growth rate for each customer class is 2 percent. The avoided cost for generation capacity is the same de-rated $75/kW-yr that was used to design the illustrative rates. Potential avoided capacity costs for transmission and distribution capacity are set at $15/kW-yr and $12/kW-yr, respectively. The avoided energy cost is the average electricity price in California, which has been estimated to be roughly $60/MWh.

Additional inputs for the system-wide impacts model include a discount rate assumption of 8 percent, an annual inflation rate of 3 percent, a reserve margin requirement of 15 percent, and an estimated line-loss factor of 8 percent. These inputs are used to estimate the net present value of system wide impacts, to calculate the system wide capacity requirement, and to determine generation savings based on customer response to dynamic pricing.

Class-level peak impacts were estimated by multiplying the customer-level impacts into the projection of participating customers. There is significant uncertainty surrounding the number of customers that would enroll in dynamic rates. This is primarily driven by the rate deployment scenario that is pursued by the utilities. If the rates are offered on a default basis, then it is expected that a much higher number of customers will remain on the rates than if they are offered on an optional basis. As a result, the system impacts were presented for both of these rate deployment scenarios.

The optional participation scenario assumes that 20 percent of all eligible customers will enroll in the dynamic rates. Conversely, the default participation scenario assumes that 80 percent of eligible customers will be enrolled in a dynamic rate. These participation rate assumptions are supported by research that was conducted in California during the SPP and similar numbers have been cited by the California IOUs in their AMI filings. The aggregate impacts estimated under the default participation scenario will always be larger than the same rate/customer pairing under optional participation. The resulting class-level peak reductions for each rate design and customer class are presented in Table 9.

Table 9: Statewide Peak Reduction (MW) by Customer Class, First Year Forecast

		Residential	Medium C&I	Large Commercial	Large Industrial
Smooth RTP	Optional Participation	155	81	36	188
	Default Participation	619	322	144	751
TOU	Optional Participation	259	117	N/A	N/A
	Default Participation	1,038	469	N/A	N/A
PTR	Optional Participation	532	N/A	N/A	N/A
	Default Participation	2,129	N/A	N/A	N/A
CPP/TOU	Optional Participation	578	197	115	794
	Default Participation	2,312	788	155	827
Peak RTP	Optional Participation	352	203	83	468
	Default Participation	1,409	813	331	1,874

The Residential customer class provides the most significant aggregate reductions, driven primarily by the large share of total load that is represented by this class. For Large Commercial and Industrial customers, the high case elasticities are used for the optional participation and the low case elasticities are used in the default participation scenarios. This reflects the logic that customers who actively choose to enroll in a dynamic rate are likely to have a greater ability to respond than customers who remain on the dynamic rate due to lack of inertia for switching.

To estimate a range of potential scenarios under which dynamic pricing could be offered in California, various combinations of dynamic rates and participation rates were modeled across the customer classes. Figure 11 illustrates the range of peak reductions that were estimated under these scenarios over a 20 year forecast horizon. The upper bound scenario in this analysis represents a nine percent reduction in the system peak load by the final year of the forecast. This upper bound scenario assumes that a default CPP/TOU rate has been implemented for residential customers along with a default Peak RTP rate for large commercial and industrial customers. The lower bound estimate in the projection yields a one percent reduction in the statewide peak load by the final year of the forecast. This lower scenario represents of an optional Smooth RTP rate for all for customer classes.

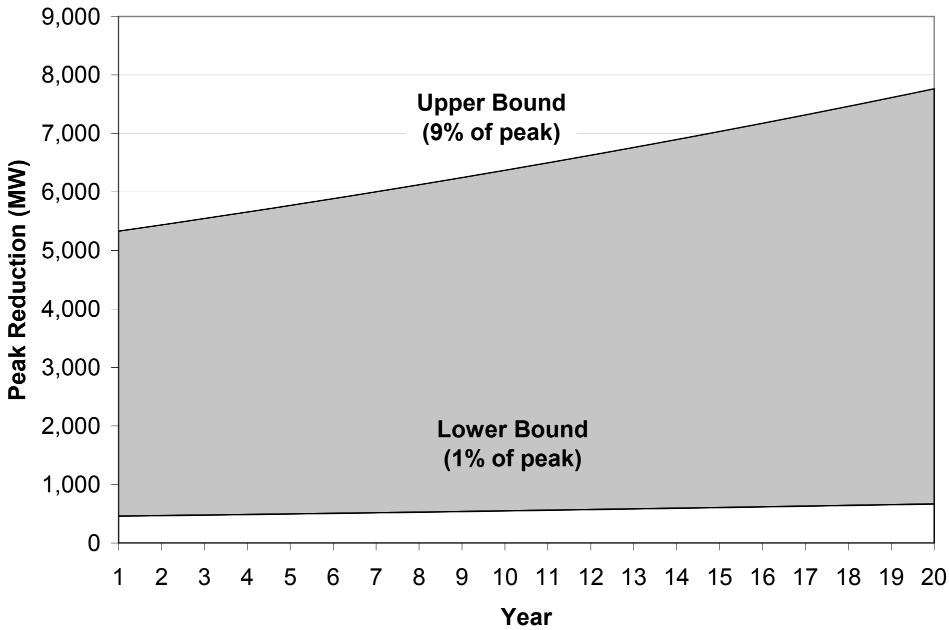

Figure 11: Range of Annual Peak Reduction Forecasts

Statewide Avoided Costs

To quantify the potential financial benefits to the California economy, these peak reduction estimates were applied to the previously described capacity and energy cost assumptions. The most significant of the avoided costs is generation capacity. However, savings from a reduced need for transmission and distribution capacity, as well as a reduction energy costs, contribute to the avoided cost estimates. The potential avoided costs for each customer class and rate design are displayed in Figure 12. This avoided cost projection applies over the same 20 year forecast horizon as the peak reduction projection. Potential benefits were estimated for both optional and default participation scenarios.

Table 10: Net Present Value of Avoided Costs (Billions of $) per Customer Class, First Year of Forecast

		Residential	Medium C&I	Large Commercial	Large Industrial
Smooth RTP	Optional Participation	$0.19	$0.10	$0.04	$0.23
	Default Participation	$0.75	$0.39	$0.17	$0.91
TOU	Optional Participation	$0.31	$0.14	N/A	N/A
	Default Participation	$1.26	$0.57	N/A	N/A
PTR	Optional Participation	$0.64	N/A	N/A	N/A
	Default Participation	$2.58	N/A	N/A	N/A
CPP/TOU	Optional Participation	$0.70	$0.24	$0.14	$0.96
	Default Participation	$2.80	$0.95	$0.19	$1.00
Peak RTP	Optional Participation	$0.43	$0.25	$0.10	$0.57
	Default Participation	$1.71	$0.98	$0.40	$2.27

Similar to the peak reduction forecast, the avoided cost projections were organized into an upper bound and lower bound scenario to project a range of system-wide financial benefits. This range is illustrated in Figure 12. The upper bound scenario produces a NPV of system wide avoided costs of $6 billion over the 20 year forecast. The lower bound estimate over the same time horizon is approximately $0.6 billion dollars.

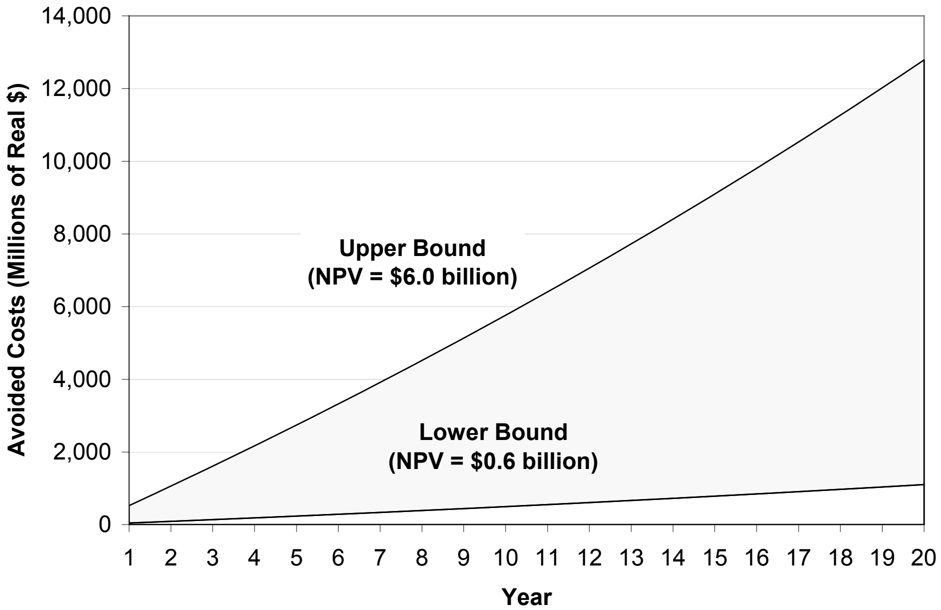

Figure 12: Range of Cumulative Avoided Cost Projections

Conclusions

Using data from a generic California utility, we have shown that it is feasible to develop dynamic pricing rates for all customer classes. Under fairly general assumptions, we have then estimated the impact of these rates on system peak loads and put a financial value on these demand reductions. We find that dynamic pricing rates have the potential to reduce system peak demands between 1 and 9 percent, with the variation in the magnitude of demand response coming primarily from two factors: which specific rates that are offered and how they are deployed. The potential benefit to California from the deployment of dynamic pricing is valued at $0.6 billion at the low end and $6.0 billion at the high end. Neither are demand response estimates nor our value estimates assume the deployment of enabling technologies such as the Energy Orb, programmable communicating thermostats or automated demand response systems. Such technologies would raise the demand response estimates and may also raise the value estimates, despite their higher costs.

These estimates are specific to California. However, the methodological process is perfectly general and should be applicable throughout North America.

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[1] Our research was funded by the Demand Response Research Center (DRRC) at the Lawrence Berkeley National Laboratory and managed by Roger Levy. We have benefited from comments by the DRRC's Technical Advisory Committee. However, the opinions expressed in the article are our own and not those of *The Brattle Group, Inc*. or the DRRC.

[2] A state law prevents the default tariff for residential customers from being changed until the bonds associated with the energy crisis of 2000-01 have been paid off.

[3] Ahmad Faruqui, Ryan Hledik and Bernie Neenan, "Rethinking Rate Design," Demand Response Research Center, August 2007.

[4] Ahmad Faruqui and Stephen S. George, "Quantifying the impact of dynamic pricing," *The Electricity Journal*, May 2007.

[5] For additional discussion about PRISM, consult Ahmad Faruqui and Lisa Wood, "Quantifying the benefits of dynamic pricing," Edison Electric Institute, January 2008.

[6] Summit Blue Consulting, "Evaluation of the 2005 Energy-Smart Pricing Plan," prepared for the Community Energy Cooperative, August 2006.

[7] The ComEd study found that, when customers were alerted on a day ahead basis that wholesale prices would be exceeding $100/MWh, they provided a greater demand response.

[8] Note that the RTP bill impacts represent an average for the full year, since this rate was designed to apply year-round.