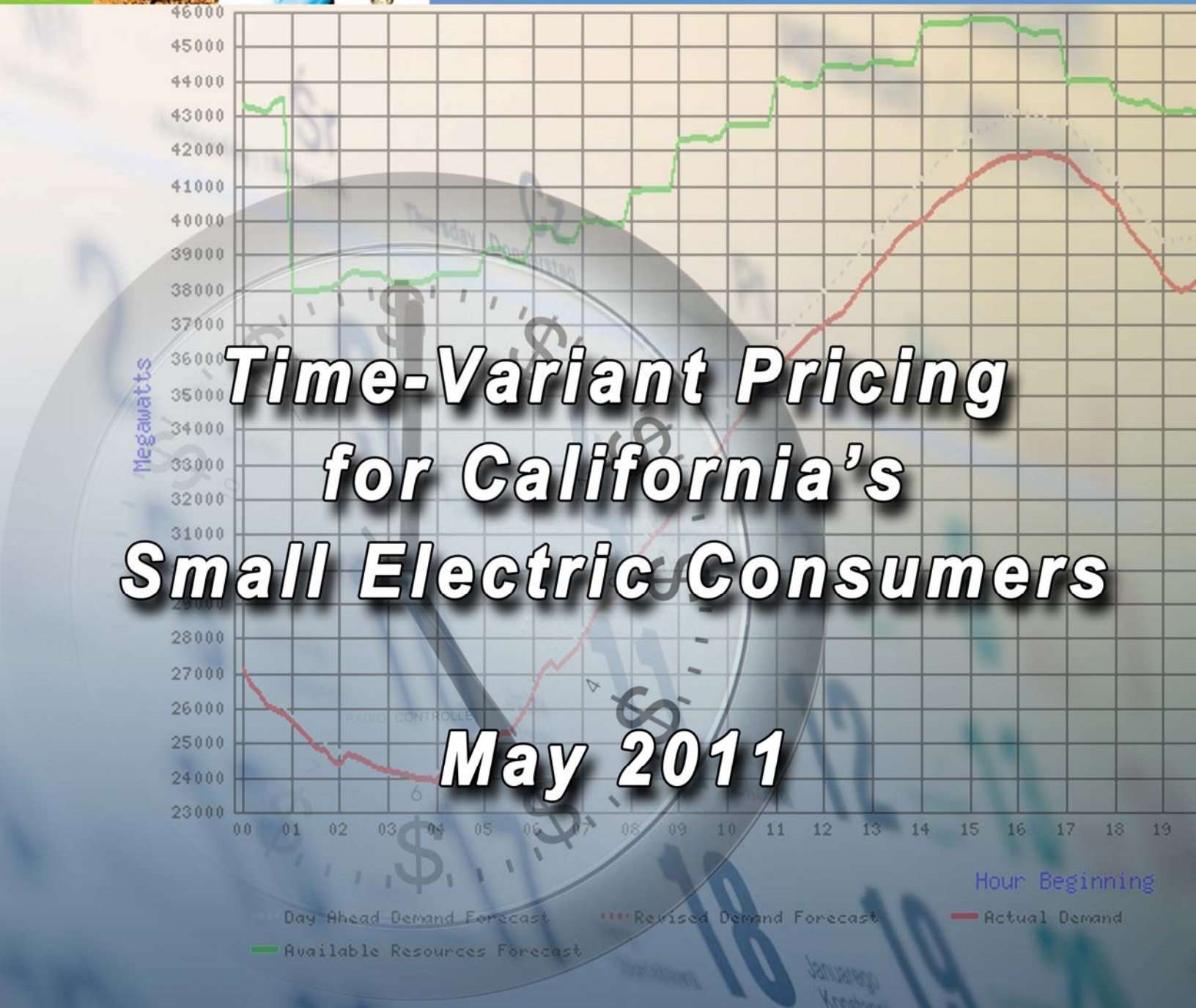
DIVISION OF RATEPAYER ADVOCATES



Time-Variant Pricing for California's Small Electric Consumers

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About DRA

The Division of Ratepayer Advocates (DRA) is an independent consumer advocacy division within the California Public Utilities Commission (CPUC) that represents the customers of California's investor-owned utilities. DRA's statutory mission is to obtain the lowest possible rates for utility service consistent with safe and reliable service levels.

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Executive Summary

This White Paper compares the efficacy of time-of-use (TOU) rates and critical peak pricing (CPP) with respect to various California energy policy and economic objectives. It shows that, on the whole, TOU rates offer comparable, if not superior, benefits to those obtainable from CPP. California energy policy in recent years has centered on three major goals: (1) Maintaining electric system reliability, (2) Controlling utility costs, and (3) Reducing greenhouse gas (GHG) emissions. This paper shows that TOU rates potentially can accomplish the first two goals about as well as CPP, and that TOU is clearly superior to CPP in reducing GHGs.

California's Energy Action Plans (EAPs) I and II placed high priority on dynamic pricing (DP) to accomplish the first two goals. Accordingly, the California Public Utilities Commission (Commission or CPUC) has prescribed CPP (a form of DP) as a default rate for nearly all customers. But the first goal of reliability is less at issue now because of today's ample generating capacity resulting from Resource Adequacy and other Commission policies. Under current conditions, the high prices in effect during critical peak events are no longer justified, as reflected in recent wholesale prices. Since April 2009, California Independent System Operator day-ahead hourly forward prices seldom exceeded $0.10/kWh, well below the $0.50/kWh - $1.20/kWh embedded in the California utilities' CPP rates. The idea of CPP emerged in the wake of the 2001 California energy crisis, when wholesale market prices were far more volatile and system reliability was at much greater risk.

The paper presents sensitivity runs that compare CPP with TOU rates over an array of economic assumptions. These runs demonstrate that TOU rates can reduce utility costs more than can CPP provided the TOU rates are fully time differentiated, with most capacity costs reflected in summer on-peak charges. Large peak to off-peak TOU price ratios are not possible if a CPP surcharge is layered on top of the TOU rate, as with Pacific Gas and Electric Company's (PG&E's) Peak Day Pricing tariffs. In such tariffs, most of the generation capacity costs are recovered in the CPP surcharge, leaving less to be recovered through the TOU portion of the tariff. Cost-reduction with TOU rates is enhanced to the extent that TOU rates can attract greater participation than CPP. Evidence points in this direction as more than half of California's large and medium commercial and industrial customers have rejected CPP in favor of TOU rates, when CPP was introduced as the default rate in 2010. The paper also asserts that TOU rates are more likely to encourage customer investment in energy efficiency while customers on CPP are more likely to adopt short-run behavioral modifications that may not persist.

The load reduction amounts in DRA's model runs are based on two sources of data. The first is a 2010 paper by Dr. Ahmad Faruqui and Dr. Sanem Sergici that summarizes the results of about 30 studies on CPP, TOU, and Peak Time Rebate programs across the country. The second is calculations performed by DRA using a model called "PRISM" that was developed by Dr. Faruqui for quantifying demand response benefits in PG&E's Advanced Metering Infrastructure proceeding. That model uses price elasticity information from the California Statewide Pricing Pilot. A wide array of avoided generation capacity and energy costs was tested.

I. Introduction

This paper attempts to answer the question: **Which form of time-varying electricity pricing best meets California's energy policy goals?** It concludes that predictable "time-of-use" (TOU) rates are likely to be superior to "dynamic pricing" rates under the relatively stable conditions prevalent in California wholesale energy markets in recent years.

Rate design can be a powerful tool in support of broader energy policy goals. This paper explains how time-variant rates can promote the California Public Utilities Commission's (Commission or CPUC) and the state's energy policy objectives, primarily (1) Keeping the lights on (reliability); (2) Minimizing greenhouse gas emissions (GHG) emissions; and (3) Controlling costs.

Since California's 2000 energy crisis, California's energy policy has centered on the following four initiatives:

1. Resource Adequacy (RA) ;
2. Energy Efficiency programs;
3. Demand Response programs; and
4. The Renewable Portfolio Standard (RPS).

Each of these initiatives is intended, to varying extents, to advance the threefold policy objectives stated above. Specifically, the third goal of cost control is advanced by avoiding or deferring new generation capacity and minimizing grid operating costs.

This paper addresses how residential and small commercial rate design can be made more efficient; thereby enhancing the effectiveness of the state's energy programs, especially energy efficiency, in promoting energy policy objectives. It also explores how different rate designs impact customers, thus contributing to customer selection of rate design options and the consequent impacts on overall utility cost of service.

Specifically, DRA recommends that most residential and small business customers transition, over time, to stable, predictable rates that vary by season and time of day. Widespread use[1] of such "time-of-use" (TOU) rates would benefit these customer classes on the whole by (1) Moderating the growth in electric utility revenue requirements; and (2) Reducing the residential and small business classes' share of those revenue requirements.[2,3] In addition, DRA believes that the current emphasis on defaulting smaller customers to dynamic pricing programs, such as critical peak pricing (CPP) and real-time pricing (RTP), is inadvisable, and that dynamic pricing should be offered to smaller customers only on a voluntary "opt-in" basis, as a supplement to TOU rates.[4]

II: Summary of Key Recommendations

The key recommendations of this paper are:

1. Most residential and small commercial customers should be encouraged to transition to TOU pricing. When the Commission[5] starts the implementation of default time-variant-pricing rates for residential customers, DRA recommends the implementation of default TOU rates. [6]

2. After a transitional period, TOU rates should be the default for most residential and small commercial customers. For residential customers, rates must continue to comply with the rate protections provided by California statute.

[1] For certain classes of customers such as low income customers and other vulnerable customer groups, special efforts should be undertaken to ensure that such customers understand TOU rate and bill impacts, and such customers should be encouraged to sign up if, and only if, they would benefit.
[2] DRA's mission is to represent the interests of residential and small business ratepayers.
[3] By "flattening" the load profiles of these customer classes, TOU rates would decrease their revenue responsibility under California's marginal cost-based revenue allocation methodology.
[4] As will be explained later, most DP proponents do not regard TOU pricing as a "dynamic" rate. A complete glossary of terms used in this white paper is contained in Appendix C.
[5] All references to the Commission or "CPUC" are intended to refer to the California Public Utilities Commission.
[6] P.U. Code Section 745 (d) allows for residential customers defaulted to time-variant rates to opt out of the default rates without incurring extra charges.

3. TOU rates should ultimately recover most marginal capacity costs (generation and distribution[7]) in the peak (especially summer on-peak) periods. However, less steeply time-differentiated TOU rates may be appropriate as a means to ease the transition to TOU pricing.
4. Dynamic rate designs (CPP and/or RTP) should be offered to residential and small commercial customers only on a voluntary opt-in basis.
5. The Commission should implement a residential peak-time rebate (PTR) program, as it can achieve some of the demand response benefits of CPP that are incremental to those provided by TOU rates alone.
6. Transition to time-varying rates should be preceded and accompanied by adequate customer outreach and education, including an aggressive program providing residential and small business customers with an integrated set of energy efficiency and demand reduction solutions through a single point of contact.
7. These recommendations and objectives should be pursued only insofar as they avoid economic harm to vulnerable subgroups of residential ratepayers, including (but not limited to): (a) Low income households, (b) Households that include a member with special medical needs.

III: Discussion

This paper addresses time-variant pricing options, suitable for small electric consumers (residential and small business customers), that would promote California's energy goals (keeping the lights on, reducing GHG emissions, and controlling costs). The key message is that time-variant pricing can, and should, incentivize customer participation in both energy efficiency and demand response programs.[8] Moreover, a balanced approach incorporating energy efficiency, demand response, and TOU rate design can

[7] The argument for TOU distribution rates is less clear-cut than the argument for TOU generation rates; it relies on the potential for deferring distribution investments by reducing the peak load on (local) distribution systems, and on the hypothesis that most local distribution peaks roughly coincide with system load peaks.
[8] Demand response can either be price-based (e.g., CPP) or technology-based (e.g., air conditioner cycling). Technology, combined with either TOU pricing or CPP pricing, greatly enhances the effectiveness of demand response (as shown below in Section X, Figure 3, which is a graph from a recent paper by A. Faruqui and S. Sergici).

maximize environmental benefits. DRA agrees that both demand response and energy efficiency are vital for meeting the state's energy goals. DRA also believes that TOU rates can be implemented on a widespread basis for small electric customers[9] while protecting vulnerable residential customers (e.g., low income or special medical needs customers) from the impact of high on-peak prices.

Some forms of time-variant pricing, such as dynamic rates (CPP or RTP), however, are not customer-friendly and may not be as effective in promoting efficient use of electricity as the more predictable and understandable TOU rate design. For reasons discussed below, DRA strongly believes that TOU pricing would, on the whole, be superior to dynamic pricing in promoting the state's energy goals. In addition, DRA believes that TOU rates will be more understandable and acceptable to residential and small business customers than the dynamic rate designs adopted in CPUC Decision (D.) 08-07-045. DRA therefore strongly recommends that the Commission re-examine its rate design guidance for the residential and small commercial sectors (cf. D.08-07-045).[10]

IV: The Energy Action Plan

As needed background, we next discuss post-2000 California energy policy and the various programs the state has undertaken to implement that policy. One of the most important policy documents underlying the Commission's dynamic pricing goals is the California Energy Action Plan II (EAP II).[11] One of the main drivers of EAP II is reducing GHG emissions that contribute to climate change which in turn gives added emphasis to several program areas:

[9] "Small electric customers" refers to residences and small businesses with maximum demands not exceeding 20 kilowatts.

[10] D.08-07-045 states (p.38): "Therefore, we will require PG&E to file an application proposing default TOU/CPP for residential customers 30 days after any change in the law that changes the AB1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers." This decision also directs PG&E to begin default CPP pricing for small business and other nonresidential customers. Such customers would be able to opt out to TOU rates but would no longer have a flat rate option. Both PG&E and DRA have filed petitions with the CPUC to delay the transition to mandatory time-variant rates for small businesses.

[11] The Energy Action Plan II is provided in Appendix A.

> Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California. …Increasing energy efficiency, demand response, and renewable resources to the maximum extent possible in California and the western region will … reduce our contribution to climate change.

The EAP II discusses energy efficiency and demand response as being key resources for meeting new energy needs:

> EAP II highlights the importance of taking actions in the near term to mitigate California's contributions to climate change from the electricity, natural gas and transportation sectors. EAP II continues the strong support for the loading order… that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency [EE] and demand response [DR] as the state's preferred means of meeting growing energy needs.
>
> As stated in EAP I and reiterated here [in EAP II], cost effective energy efficiency is the resource of first choice for meeting California's energy needs. Energy efficiency is the least cost, most reliable, and most environmentally-sensitive resource, and minimizes our contribution to climate change.

The EAP II also supports the use of rate design as a tool in meeting its goals:

> California is in the process of transforming its electric utility distribution network from a system using 1960s era technology to an intelligent, integrated network enabled by modern information and control system technologies. This transformation can decrease the costs of operating and maintaining the electrical system, while also providing customers with accurate information on energy use, time of use, and cost. **With the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability.** To achieve this transformation, state agencies will ensure that appropriate, cost-effective technologies are chosen, emphasize public education regarding the benefits of such technologies, and develop tariffs and programs that result in cost-effective savings and inducements for customers to achieve those savings. (emphasis added)

Notwithstanding this policy prescription, the analysis presented below shows that the state could better achieve its policy objectives, especially GHG and cost reduction, by establishing and promoting TOU rates rather than dynamic pricing tariffs.

V. How Rate and Non-Rate Programs Contribute to State Energy Policy Goals

Non-Rate Programs

As mentioned previously, there are four main initiatives that have been employed in California to fulfill the state's energy goals. They are Resource Adequacy (RA), the Renewable Portfolio Standard (RPS), energy efficiency, and demand response. Though all four initiatives make some contribution to each of the objectives, the *main purpose* of RA is reliability and that of RPS is to reduce GHG emissions.[12] In contrast to these supply-side resources, demand-side resources such as cost-effective energy efficiency and demand response contribute to all three energy goals. Energy efficiency enhances reliability, reduces overall procurement and grid operating costs, and it contributes to reducing GHG emissions. Demand response (DR) programs[13] also contribute significantly to grid reliability. Since DR helps to reduce the cost of procuring peaking generation, it can also help control costs. However, demand response has limited impact on GHG emissions, and appears to be only moderately cost effective at present.[14]

A key question is whether energy efficiency or demand response makes a greater contribution to meeting the state's energy goals. Demand response can be an effective strategy for keeping the lights on and certainly for deferring new peaker generation, provided it is counted for RA and long-term procurement planning purposes.[15] However, because most demand response programs operate only during a relatively

[12] RPS does not contribute to controlling costs because many renewable resources are not cost-effective.
[13] Like energy efficiency , demand response is also a demand-side resource, however, unlike energy efficiency, demand response accomplishes relatively little toward GHG reduction, primarily because demand response is focused only on the top 1% of peak hours, while energy efficiency reduces demand over a much broader set of hours.
[14] In part, this is due to the ample amount of generation capacity available as a result of RA and other supply-related programs, and the cost of demand response incentives. Demand response could be more cost-effective under conditions of a "leaner" supply-demand balance. Though DR is oriented toward reliability, today's actual reserve margins exceed planning reserve margins, making the risk of the lights going out relatively low. DRA also asserts that energy efficiency makes a greater contribution to controlling costs than does demand response.
[15] For demand response to enhance reliability in a cost-effective manner, DR must be counted towards meeting the California Independent System Operator's target reserve margins, and some DR programs are not. Perhaps the emphasis placed on demand response today is a legacy of the energy crisis and is not based on today's conditions.

few hours of highest peak load (e.g., about 1% of hours or fewer than 100 hours per year), demand response is relatively poor at reducing GHG and grid operating costs.[16] For these reasons, and since energy efficiency to some degree, meets all three state energy goals, DRA agrees with the EAP that it should receive priority relative to DR in the "loading order" and in policy planning.

We can conclude that demand-side non-rate programs, especially energy efficiency, contribute to meeting state's energy goals as valuable adjuncts to supply-side programs. Further, rate design is a valuable complement to the Commission's demand-side non-rate programs. In Section X, DRA will demonstrate that TOU rates reduce energy consumption and GHG emissions more than does CPP, thus providing a better complement to the Commission's demand-side non-rate programs.

Rate Programs

In residential rate design, tiered rate design with inverted blocks (in use in California for the last 30 years) clearly promotes energy conservation, and thus complements energy efficiency programs. The question of whether time-varying rates are superior to tiered, non time-varying rates is not addressed here.[17] As mentioned above, the central question for this paper is: **Given a determination to adopt time-varying rates, which rate design is best?**

In designing time-varying rates, the question arises whether a critical peak rate that would operate only during approximately one percent of the hours of the year should also be included in the tariff. DRA will argue, under California wholesale energy market

[16] Based on standard values for marginal energy and generation capacity costs, a uniform one kWh reduction year-round decreases generation costs by up to eight times more than does one that only reduces load by one kW during one percent of the hours per year. For now, a simple example will illustrate this principle. If a marginal energy cost of 7 cents/kWh and a marginal capacity of $85/kW-yr are assumed, a uniform 1 kWh reduction all hours of the year produces a savings of almost $700, while a 1 kW reduction of load during 1 percent of the hours produces a savings of approximately $91. This does not include the cost savings from reducing the need to purchase GHG allowances in the new cap and trade market set begin next year. A more complex example is given for a CPP and a TOU rate later in this paper. In actual practice, the relative impact of energy efficiency and demand response programs on reducing costs is significantly less, especially for EE programs that focus on end uses that are only used during the summer on-peak.

[17] For a discussion of marginal cost-based pricing and TOU pricing, see Friedman, Lee S., The Importance of Marginal Cost Electricity Pricing to the Success of Greenhouse Gas Reduction Programs, a conference draft for presentation on November 6, 2009 at the Annual Research Conference of the Association for Public Policy Analysis and Management, Washington, DC.

conditions prevalent over the last few years, that Critical Peak Pricing adds little incremental value compared to the burden it would place on customers and the greater implementation costs it will impose on the utility.[18] Also, the analysis presented in Section X below indicates that the total economic benefit from offering a time-varying rate could be maximized by spreading capacity costs over a broader set of hours (e.g., 600 summer peak hours, as typical for a TOU rate), as opposed to 60 hours for a typical CPP rate.

Further, TOU rates are likely to work synergistically with both energy efficiency and RPS. As long noted by solar advocates, TOU rates increase the benefit to the customer for installing rooftop solar photovoltaic systems. Indeed TOU rates provide a better signal of the true value of both solar and energy efficiency investments. Finally, by increasing *off-peak* loads, TOU rates can assist in integration of wind generation.

VI: The Economic Case for Dynamic Pricing

Before the efficacy of TOU relative to CPP rate design can be discussed, we must first understand why dynamic pricing[19] has been a significant component of state energy policy. We will begin with the purest form of dynamic pricing, which is real-time pricing (RTP). With RTP, the rate can vary each hour depending on system conditions such as wholesale electricity costs and the supply-demand balance. In this rate design, neither the timing of when certain rates will occur nor the rates themselves are pre-specified in a tariff. CPP is a simplified approximation to RTP in that the rate is pre-specified, as is the number of hours per year it can be charged, but the timing of when this rate will be levied is not pre-specified in tariffs.[20] As explained in section VII below, CPP is a rather crude approximation to RTP in that real-time California wholesale energy prices do not

[18] To reduce the potentially negative impact on customers, a CPP rate would need to be set significantly below the $0.50 - $1.20 CPP rates that are currently established by, or adopted for Pacific Gas and Electric Company (PG&E). See, e.g., PG&E's SmartRate, E19 (T,P,S) PDP rates, or the A1-PDP, A6-PDP, and A10-PDP rate schedules.
[19] Appendix B presents a brief overview of dynamic pricing concepts.
[20] In many cases, this rate is limited to the summer on-peak periods which cover roughly 10 percent of the hours of the year.

currently and for the foreseeable future exhibit the dramatic increases expected by dynamic pricing proponents under CPP event conditions.

In contrast to RTP and CPP, TOU rates are generally not regarded as "dynamic" because neither the timing nor the rates themselves are left unspecified; therefore TOU rates cannot adjust "on the fly" to reflect actual system conditions. However, as will be shown in the sections following this one, TOU rates can make a substantial contribution to reducing system peak load. This is partly because the ratio of summer-on peak to off-peak rates can be set as high as 4 to1 if, in rate design, most generation and distribution capacity costs are allocated to the summer on-peak period.[21]

RTP has always been the "gold standard" for dynamic pricing advocates. The case for RTP is laid out in a 2009 paper by Severin Borenstein, who is a leading advocate of RTP. DRA will present his argument, to a large extent, in Dr. Borenstein's own words.[22]

First, Dr. Borenstein argues, on economic grounds, that RTP most accurately reflects the opportunity costs of consuming electricity:

> Long before U.S. electricity restructuring began in the 1990s there was a recognition that the marginal cost of producing electricity could change significantly hour to hour. Combined with the high cost of storing electricity, this meant that the true opportunity cost of consuming electricity also would vary constantly. For many decades economists have argued that retail electricity prices should fluctuate accordingly - this is known as real-time pricing (RTP)…

As for what these opportunity costs are, he goes on to argue that, with a deregulated energy market, prices can rise above marginal costs when demand outstrips supply. When this happens, the fastest and least expensive way for the supply-demand balance to be restored is to incentivize demand reduction through rate design. He states that the absence of retail pricing design programs, such as RTP, during California's 2001 energy crisis, exacerbated the magnitude of wholesale price increases:

[21] DRA does not necessarily advocate a 4 to 1 TOU price ratio as a default rate because high ratios of peak to off-peak rates could have negative consequences in terms of rate shock, extreme geographical differentials, economic and operational disruption to small commercial customers, and lack of customer acceptance of time-varying rates. However, combination TOU-CPP rate designs, such as PG&E's "Peak Day Pricing" (PDP), necessarily weaken the time-differentiation of the TOU rate components, often resulting in a price differential less than 1.5 to one. This effect is discussed below in Section XIII: "Combination Rate Designs."

[22] NBER Reporter: Research Summary 2009 Number 1 Borenstein, S. Electricity Pricing That Reflects Its Real-Time Cost. The italicized text in the following excerpts are not italicized in Dr. Borenstein's original article.

> Wholesale electricity markets were deregulated in many parts of the United States in the late 1990s. The idea was that electricity generation could be a competitive industry with many generators vying to sell their output into a common power market. The underlying economic model for this market, however, required that prices occasionally rise to well above the marginal cost of producing most units of output in order for firms to earn operating profits on infra-marginal units, operating profits that allowed the firm to cover its capital cost, at least in expectation. In the simple framework of a constant marginal cost of each generator up to its capacity, this meant that the market had to sometimes clear "on the demand side." That is, high prices would occur at times of high demand or reduced supply, and those high prices would cause quantities demanded to decline until they were in line with system capacity. Such price-responsive demand would constrain prices from jumping too high, whether the tight market was caused by a true supply shortage or an artificial shortage caused by some firms exercising market power. What went largely unnoticed at the time was that the technology and market organization to enable RTP was not in place in any of the markets headed towards deregulation.

Given the opportunity costs of producing energy, Dr. Borenstein argues that the cost of implementing RTP programs is several times less the gains in consumer welfare:

> In the [2003 paper by S. Holland and S. Borenstein], we used simulations to examine how large the societal gains from switching to RTP are likely to be. These simulations used realistic production cost parameters to analyze how the long-run equilibrium investment and pricing would change as more customers moved from a time-invariant pricing plan to RTP. The result was significant and at the same time sobering.
>
> It was significant in that the potential gains from RTP were almost certainly many times greater than the estimated costs of implementing such a program. In addition, the gains were largest for the first tranche of customers moved to RTP. In fact, with reasonable elasticity assumptions, it is likely that one-half of the possible total surplus gain could result from putting only one-third of all demand on RTP. This was important because the cost of implementing RTP at the residential level may be substantially higher -- because each household consumes fairly little yet has nearly the same metering and billing costs as a large industrial customer -- so an RTP program is likely to start with large industrial and commercial customers.

He argues that, though the actual efficiency gains are only on the order of 5 percent, he regards them as both "significant" and "sobering":

> The results were sobering because as exciting as the prospect of "getting prices right" may be to economists, the potential gains were likely to be only 5 percent or less of the energy bill. And energy is generally only about half of the entire electricity bill, the remainder being transmission, distribution, and customer administration costs. It still amounted to hundreds of millions of dollars in California, but it wasn't going to fundamentally change the cost of supplying electricity. The reason for this is worth highlighting: in an electric system that must always stand ready to meet all demand at the retail price, the cost of a constant-price structure is the need to hold substantial capacity that is hardly ever used. But utilities optimize by building "peaker plants" for this purpose, capacity that has low capital cost and high operating cost. The social cost of holding idle capacity of this form turns out to be not as great as one might think. The analysis, however, does not capture some other potential benefits of RTP, including reduced vulnerability to supplier market power and greater resiliency in emergency situations, such as transmission outages, so the simulation estimates are only a piece of the gains.

It is interesting, however, that Dr. Borenstein does not attribute significant environmental benefits to demand response programs, which is consistent with what DRA argued in the previous section.

> While RTP holds potential for real efficiency gains, it is unfortunately often confused with energy efficiency programs that are designed to reduce overall consumption. RTP is even occasionally touted for having environmental benefits. While it might cause decreased consumption in some cases, there is no evidence that the effect on net would generally be in that direction.

To summarize the case for RTP, it is founded on the following premises:

1. The marginal cost of producing electricity could change significantly hour to hour.
2. Wholesale electricity markets were deregulated and many generators [are] vying to sell their output into a common power market.

3. [Wholesale] prices[23] [must] occasionally rise to well above the marginal cost of producing most units of output, and high prices would occur at times of high demand or reduced supply.
4. High [retail] prices would cause quantities demanded to decline until they were in line with system capacity.

VII: CPP as an Alternative to RTP

While numerous U.S. utilities have experimented with RTP, with few exceptions, RTP, like other forms of dynamic pricing, has failed to gain much traction even in deregulated energy markets.[24] In California, RTP has generally been limited to experimental programs with few participants. In part, this may be due to the fact that spot market trading has been thin in California, and there is no robust hourly wholesale market. Further, hourly wholesale market prices (e.g., CAISO day-ahead hourly forward market prices) have shown greatly diminished volatility in recent years.[25] This lack of price volatility implies that RTP, if implemented, might not lead to the price response to system conditions expected by dynamic pricing proponents. In recent years, wholesale prices seldom or never rose much above marginal energy costs.

To overcome the lack of a sufficiently volatile hourly pricing signal, dynamic pricing proponents have invented the simpler, but highly artificial pricing scheme called "Critical Peak Pricing." With CPP, as implemented in California, the utility announces 24 hours in advance that the next day will be a critical peak event day and that for 4 to 6 hours, electricity prices will be set at a fixed, predetermined level often 5 to 10 times greater than the average per kWh price. CP event days are intended to be called primarily under extreme heat conditions or when supply disruptions are anticipated. California

[23] It is not specified in Dr. Borenstein's paper whether the "prices" refer to wholesale prices or retail prices, but, clearly, Dr. Borenstein believes that the two should move in tandem.
[24] See, for example, the report "Dynamic Pricing Evaluation for Washington" sponsored by the National Association of Regulatory Utility Commissioners, published January 2011.
[25] As described in recent PG&E testimony in Phase 2 of its 2011 General Rate Case, A.10-03-014, filed March 22, 2010, Exhibit PG&E-1, Chapter 9, pp. 9-2 to 9-3. See also, Figure 1 in Section VIII below.

utilities have limited the number of annual CP event days to between 9 and 15 annually. Therefore, at most, 90 hours per year would be subject to high critical peak prices.[26]

While CPP does indeed introduce price volatility, it is highly artificial in that it does not necessarily reflect the operation of market forces. It also is unclear whether some implementations of CPP are based on a sound marginal cost analysis.[27] Therefore, unlike RTP, it would be difficult if not impossible to establish even a theoretical basis to assert that CPP is efficient. Notwithstanding the lack of a good theoretical foundation for CPP, the CPUC has ordered that it be offered to all customer classes of at least one large California utility,[28] on the grounds that CPP is a demand response program and is therefore required by, or at least consistent with, state energy policy.

In the following section, we critique the effectiveness of both CPP and RTP as demand response programs, and compare the efficacy of dynamic pricing in general with TOU pricing in promoting the state's broader energy policy goals.

VIII: A Critique of Dynamic Rates

Caveats Applicable to Both RTP and CPP

There are several reasons why dynamic pricing is unlikely to achieve the benefits claimed by its proponents and should be considered only as an optional supplement to TOU pricing, rather than vice versa.

1. California wholesale markets lack the price volatility which Dr. Borenstein states is necessary for a well-functioning RTP rate design.

[26] See, PG&E's rebuttal testimony in A.09-02-022, Ex. PG&E-7, p.22, August 21, 2009.
[27] Some earlier forms of CPP rate design recovered 100% of the marginal generation capacity cost in the CPP rate itself. This is erroneous given differences between the operation of a combustion turbine (CT) generator, which is the basis for most calculations of generation capacity costs, and the operation of a CPP program. While a CPP program is constrained to operate only 1% of the time, a CT is not. Furthermore, the option value of a CT is higher because it can be called almost instantaneously, whereas most CPP programs must be called 24 hours in advance. In calculating a CPP rate, the value of the CT must be decreased to reflect these issues. In addition, many quantifications of the CT price itself may not adequately reflect the true supply-demand balance in the real world wholesale market and how that affects capacity prices.
[28] PG&E, in Decisions Nos. 08-07-045 and 10-02-032.

2. CPP rate designs have no relation to market prices or possibly to a sound marginal cost analysis, and therefore they may have no supportable efficiency basis.
3. Recent research, cited by leading dynamic pricing advocate Dr. Ahmad Faruqui, indicates that customer response to high prices tends to diminish with additional price increments.[29] This suggests that consumer response to very high critical peak prices may be less than dynamic pricing proponents expect based on previous elasticity studies.[30]
4. As Dr. Borenstein notes, RTP is unlikely to offer significant reduction in overall energy usage. The same could be said about CPP, due to the fact that customers will receive price signals to conserve only in about 1% of the hours in a year. Thus, neither RTP nor CPP are likely to significantly help California reduce GHG emissions.
5. Prices are unpredictable in dynamic rate designs, making it difficult for customers to plan for their energy expenses and analyze opportunities for energy efficiency investments.
6. Dynamic rate designs are complex and difficult for customers to understand, and the success even of CPP is vitally dependent on the utility effectively notifying customers of individual critical peak events and customers being able to reduce their usage after receiving notice.[31]

As mentioned above, wholesale market hourly prices have shown greatly diminished volatility in recent years. This lack of price volatility implies that RTP, if implemented, might not lead to the price response to system conditions expected by dynamic pricing proponents. There is a good reason for the diminished price volatility of recent years in California: many steps have been taken to alleviate scarcity of generation resources

[29] As described in Dr. Faruqui's testimony for PG&E in Phase 2 of its 2011 General Rate Case, A.10-03-014, filed March 22, 2010, Exhibit PG&E-1, Chapter 11, pp. 11-9 to 11-10.

[30] In addition, recent California utility data suggests that customer response tends to diminish on the hottest days. The 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation, March 24, 2011 Draft report, issued by Freeman, Sullivan, and Co. states, at page 2, that the lowest CPP event impacts for SCE and SDG&E occurred on the hottest day. The report raises the possibility that response decreases with extreme temperature but declines to draw that conclusion, instead citing other factors that could account for the observations.

[31] The cost to customers of automating this notification process through home area network devices and to utilities in implementing the required back office information technology systems is non-trivial. Nor is this technology widely available at a low-enough cost to enable mass-market penetration.

and thus limit or eradicate the kind of market power that lead to price volatility in 2000 and 2001.

Dr. Borenstein explains what caused California's "energy crisis":

> The view of most economists who have studied the [2000-01 California] electricity crisis is that it resulted from a true scarcity in the wholesale market greatly exacerbated by the ability of a few sellers to exercise significant market power.[32]

Regardless of the correctness of this view of the energy crisis, there were certainly curtailments, CAISO staged alerts, and high wholesale prices during the energy crisis. In response to the crisis, the CPUC completely revamped the investor-owned utilities' procurement processes in the years following the crisis. Most relevantly, the CPUC established the Resource Adequacy proceeding[33] which requires "load serving entities" to forecast their peak load and acquire sufficient generation capacity to maintain a 15% reserve margin. In response to this and other CPUC initiatives encouraging building new generation, **there is no longer a scarcity of generation in California.**

What this implies for wholesale prices is that they are no longer very volatile. Quoting from PG&E's RTP testimony in its 2011 General Rate Case (GRC) Phase 2 application:

> PG&E recognizes that CPUC and California Energy Commission (CEC) policy staff, academic economists and policy experts, and a succession of both CPUC and CEC commissioners have attached great expectations to the future of RTP for at least the last 15 years. **PG&E cautions, however, that the first several quarters of day-ahead hourly CAISO prices have shown very little variation outside of the range of ordinary time-of-use (TOU) generation energy charges** (much less, at the price levels of 50 cents to $1.00 per kilowatt-hour (kWh) and more that will be effective under the new PDP tariffs), **with only infrequent instances of even moderately higher-priced or lower-priced blocks of hourly prices.** There has been very little incorporation of capacity costs to be observed in the first several quarters of day-ahead hourly CAISO

[32] NBER Reporter: Research Summary 2009 Number 1 Borenstein, S. Electricity Pricing That Reflects Its Real-Time Cost.

[33] According to the CPUC's website, the Resource Adequacy program has two goals. First, it provides sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. Second, it is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. Commission staff also lead annual RA proceedings (R.09-10-032 is the most recent proceeding) to refine the RA program.

> prices, given that **in the entire summer 2009 hourly prices reached even 10 cents per kWh on just two or three occasions.** While the general nature of the day-ahead hourly CAISO prices observed to date are broadly reflective of a stable wholesale market, PG&E cautions that retail RTP tariffs linked to these prices are likely to provide customers with less dramatic price incentives to shift or reduce load than might first have been envisioned for the program.[34]

The lack of volatility in recent CAISO day-ahead hourly forward market prices is shown graphically in Figure 1. In this figure, the 8,760 hourly prices observed in 2010 are sorted in decreasing order (blue curve). The price data is superimposed on hourly load data, also sorted in decreasing order (red curve).

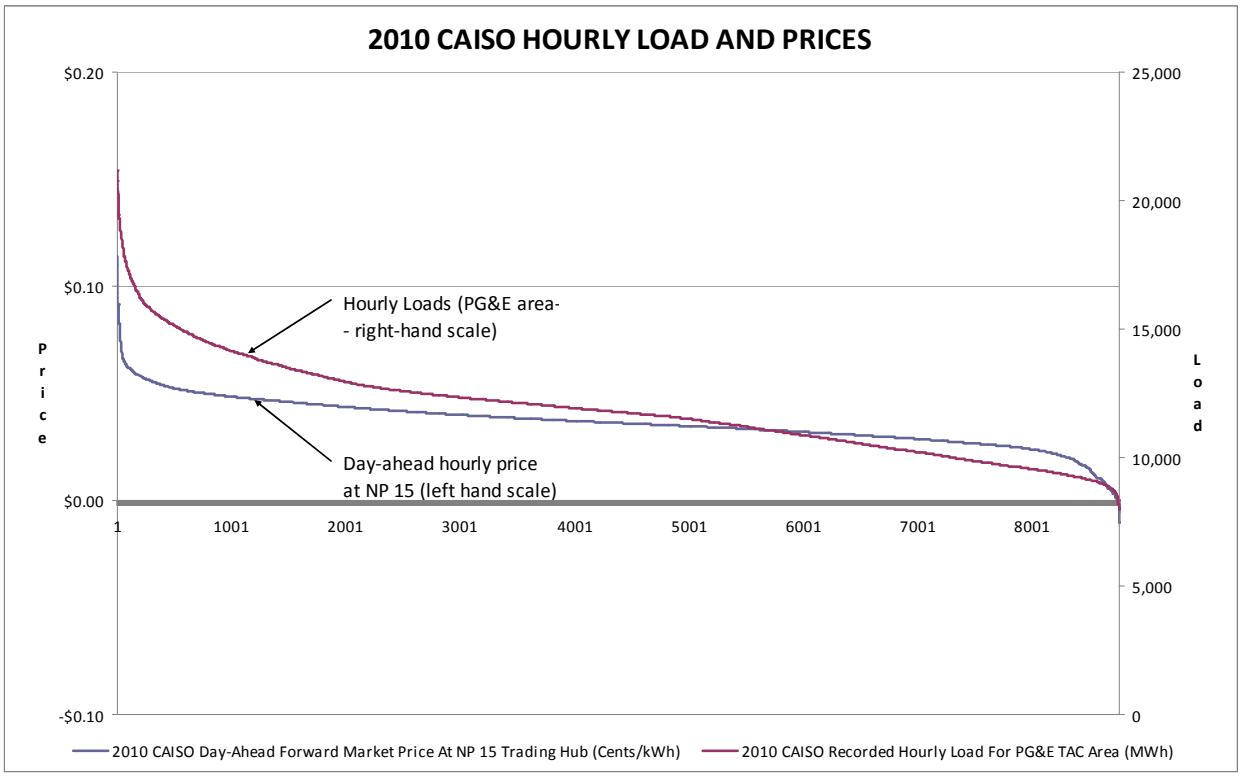

Figure 1: CAISO Hourly Loads and Prices

Several interesting conclusions can be drawn from Figure 1:

(1) Hourly prices were considerably flatter, in 2010, than hourly loads. This suggests that real time prices would not have provided a strong signal, in 2010, to reduce peak load (as the above-quoted PG&E testimony suggests).

[34] Testimony of Andrew Bell in Phase 2 of PG&E's 2011 General Rate Case, A.10-03-014, filed March 22, 2010, Exhibit PG&E-1, Chapter 9, pp. 9-2 to 9-3, emphasis added.

(2) The highest hourly price attained in 2010 was only slightly above $0.10 per kWh, far below PG&E's CPP event hour prices which range from about $0.80 to $1.20 per kWh. This disparity indicates how artificial CPP event hour prices can be.

DRA believes that the observed lack of volatility of day-ahead hourly CAISO prices (exemplified by Figure 1) is a result of the ample generating capacity now available to the California energy market as a result of RA and other CPUC initiatives. How the resulting rightward shift in the supply curve has affected wholesale prices is shown graphically in Figure 2.

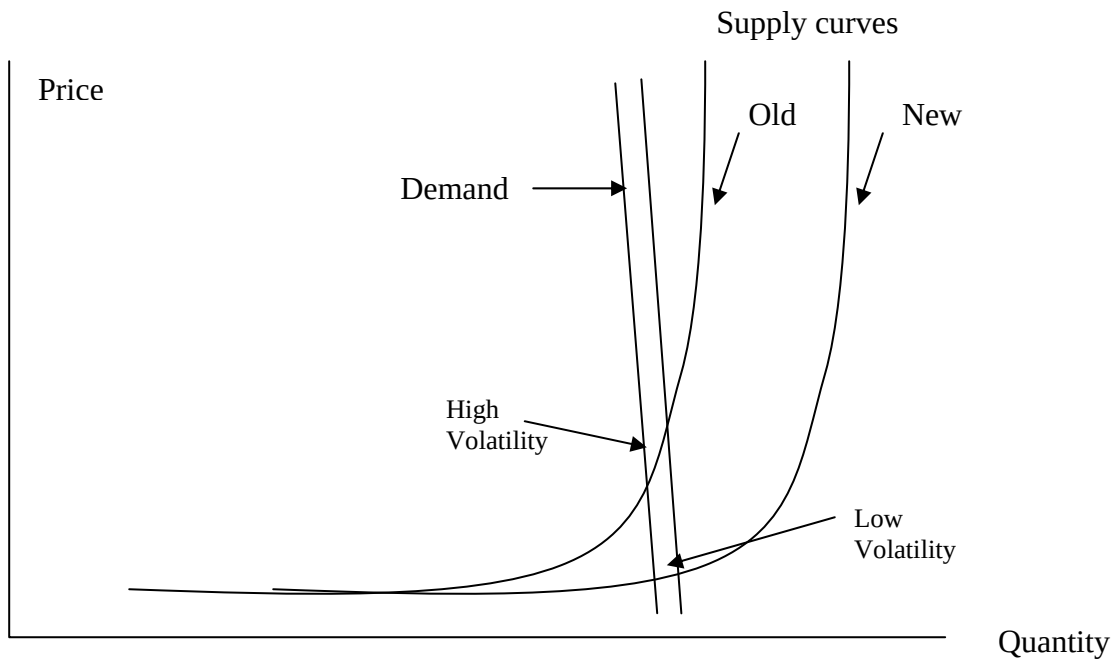

Figure 2 – Right-Shifted Supply Curve

In short, the conditions of episodic scarcity and high wholesale prices that motivated dynamic pricing no longer exist in California.

Caveats Specifically Applicable to CPP

Due to lack of wholesale price volatility, RTP is no longer an effective demand response strategy, and thus many proponents of dynamic pricing advocate for the artificial price volatility created by CPP to induce demand response. In fact, early proponents of CPP advocated setting the CPP rate perhaps higher than it should be based on marginal cost principles to induce the desired demand response. Many studies have shown that customer price elasticities are too low to elicit the kind of response being sought unless the CPP price is deliberately set very high. But, as stated before, this kind of thinking often has resulted in an artificially high CPP that does not reflect the real world wholesale market or sound marginal cost analysis. Accordingly, DRA questions whether it is right to manipulate customer demand through artificial pricing. Instead, DRA advocates merely setting the price of electricity in a manner that reflects, but does not exaggerate, daily and hourly cost variations, and then letting customers themselves decide whether they want to pay that price based on their own energy needs and priorities.

Further, even high CPP prices may not have the demand-reducing effect that its proponents expect. A very interesting quote from CPP proponent Dr. Faruqui illustrates the point:

> It is also my [Ahmad Faruqui's] opinion that raising prices to incent conservation should only be carried out to the extent it is based on the marginal cost of supplying energy to customers. The goal should not be to maximize conservation regardless of cost. If that was the goal, then there would be no limit to the prices that should be charged in the upper tiers. **Moreover, there is evidence from a variety of pricing experiments that have been carried out in North America during the past decade with dynamic pricing which suggests that customer response to rising prices diminishes with the magnitude of higher prices.** There is no reason to believe the same diminishing returns phenomenon would not be observed with inclining block rates of progressive severity. (A.10-03-014, Ex. PG&E-1, Faruqui, Ch. 11, Q&A 13, emphasis added).[35]

[35] Quote in bold refers to Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity: A Survey of the Experimental Evidence," January 10, 2009. Can be downloaded from: http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf

While Dr. Faruqui argues these diminishing returns impair the effectiveness of heavily inclining block rates, the same effect could be expected with CPP. Indeed, the highest rate in PG&E's existing inclining block rate schedule is about $0.40/kWh, while PG&E's CPP rates range from $0.50/kWh - $1.20/kWh. Certainly customer response is likely to diminish as prices approach, and surpass, the stratospheric $1 per kWh level. Not having good arguments for dynamic pricing based on economic efficiency, dynamic pricing proponents have touted dynamic pricing as a means "to get the most value out of the [smart meter] investment."[36] A rebuttal to these lines of argument is offered in the next section.[37]

IX: Is Dynamic Pricing Required to Justify the Cost of Smart Meters?

Demand Response, mainly through CPP rates, was used in the Smart Meter (otherwise referred to as Advance Metering Infrastructure or "AMI") business cases presented by California's three largest investor-owned electric utilities to justify about a third of the cost of the Smart Meter deployment. Dr. Faruqui sets forth the argument as follows:

> **To effectuate demand response, some type of dynamic pricing will have to be instituted in retail markets.** The central question in all of these assessments is: Will customers respond to higher prices by lowering peak demand and if so, by how much? The answer will help state regulators determine whether or not to proceed with authorizing the deployment of AMI in their jurisdictions. Is it worthwhile to pursue AMI? The answer is a conditional yes. **Two things have to occur to make this a sound decision. First, AMI should be accompanied by dynamic pricing to get the most value out of the investment.** This represents a major change in the pricing paradigm and will be actively debated by commissions in every state before a consensus is arrived at. **Second, customer response to dynamic pricing has to create savings in avoided capacity and energy costs to overcome the net investment in AMI** (i.e., that amount which is not offset by savings in distribution

[36] See, for example, A. Faruqui and S. Sergici, Household Response To Dynamic Pricing Of Electricity—A Survey Of The Empirical Evidence, February 15, 2010.
[37] Ibid.

> system costs). The second condition is largely an empirical issue and provides the impetus for this paper.[38]

The citation above seems to imply that dynamic pricing is the only form of demand response. There are, however, demand response programs operating in California that are not price-related. Air conditioner cycling is one example. While demand response is an ongoing and effective means of reducing peak demand in California, only a portion of current demand response programs fall into the category of dynamic pricing. Unfortunately, the relative cost-effectiveness of Smart Meters and non price-driven demand response alternatives, such as air conditioning cycling was not compared in the evaluation of the Smart Meter business cases.

Granting the assumption that dynamic pricing does produce demand response benefits, DRA questions whether it is the only way to leverage Smart Meter investments to achieve these benefits, as the quotation above seems to assert. In addition to dynamic pricing, **Smart Meters enable other forms of time-variant pricing, such as TOU pricing, which may well create more value from the state's Smart Meter investment than dynamic pricing.** The next section argues that TOU pricing is potentially superior to dynamic pricing in achieving the state's threefold energy goals.

[38] A. Faruqui and S. Sergici, Household Response To Dynamic Pricing Of Electricity—A Survey Of The Empirical Evidence, February 15, 2010.

X: TOU Rates versus CPP

Several papers have appeared in recent years comparing the results of TOU and dynamic pricing studies. The following graph, from a 2010 paper by Faruqui and Sergici,[39] illustrates the typical findings of these papers:

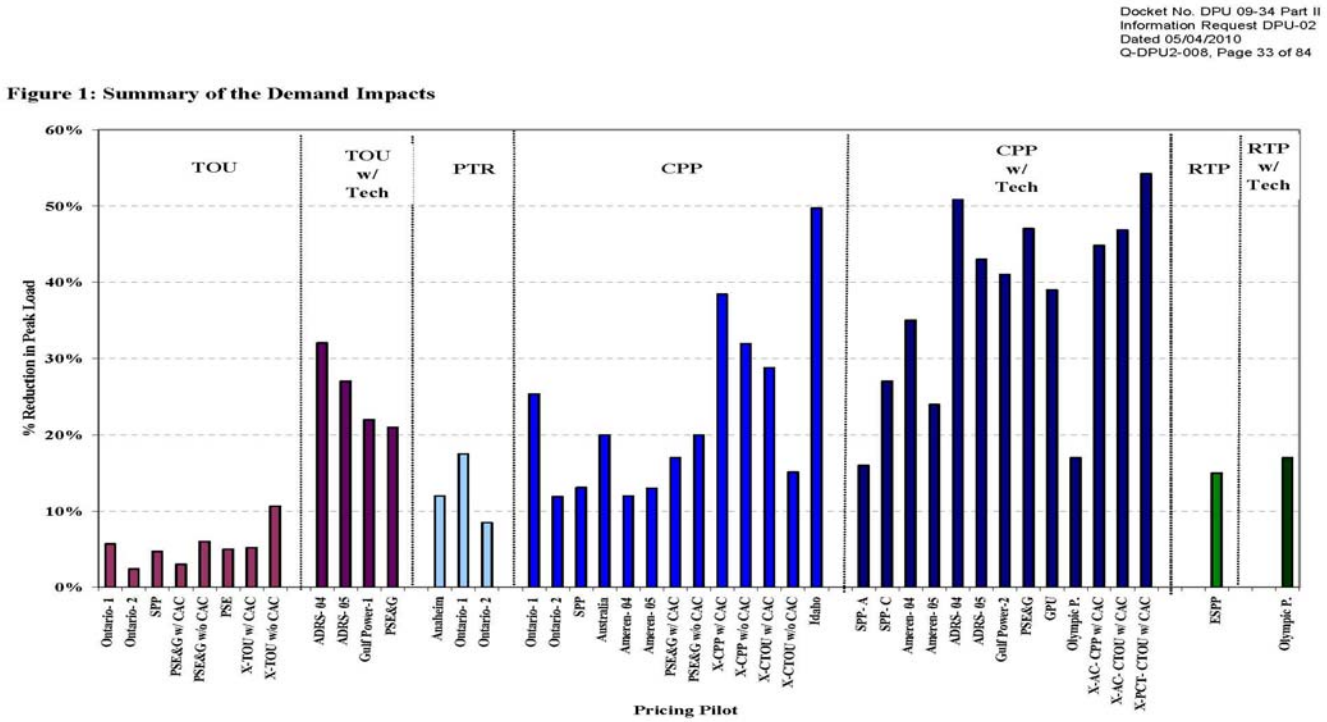

Figure 3 – Demand Impacts of Various Rate Designs

This, and similar graphs included in recent papers, plot "% reduction in peak load" for a large number of pricing studies grouped by type and technology. In a similar vein, Table 2, from the same paper (Faruqui and Sergici) but presented in tabular form, summarizes the impacts of 28 "observations" of impacts of rate design on peak demand. Table 2 reports the mean results, the lower and upper 95 percent confidence interval bounds, and the lowest overall (minimum) and highest overall (maximum) results.

[39] Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity: A Survey of the Experimental Evidence," February 15, 2010, p.32.

Table 2 – Summary Impacts of Rate Programs[40]

Rate Design	N	Mean	95% L.B.	95% U.B.	Min.	Max.
TOU	**5**	**4%**	**3%**	**6%**	**2%**	**6%**
TOU w. Tech.	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	**8**	**17%**	**13%**	**20%**	**12%**	**25%**
CPP w. Tech.	8	36%	27%	44%	16%	51%

One might infer from Figure 3 and Table 2 that TOU pricing is inferior to CPP in its impact on peak load. Such an inference can be correct yet highly misleading at the same time, for several reasons.

First, the TOU rate differentials in the programs included in the Faruqui-Sergici paper are modest. Some of the TOU rate studies included had summer peak rates less than 20 cents and ratios of peak to off-peak prices as low as 2 to 1[41] or less. Indeed, the Final Report of the Idaho Residential Pilot Program Study acknowledges that a higher peak to off-peak ratio would have produced more significant results:

> This [result] indicates that the TOD [i.e., TOU] rates had no effect on shifting usage. However, in light of the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It suggests that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off peak periods.[42]

Fully cost-based TOU rate designs, in contrast, often top off at about 30 to 50 cents per kWh for summer peak periods. As indicated above, in California, summer peak to off-peak ratios of 4 to 1 are supportable if nearly all marginal generation and distribution capacity costs were assigned to the summer peak period.[43] Note that such large peak

[40] From Faruqui and Sergici, "Household Response to Dynamic Pricing of Electricity: A Survey of the Experimental Evidence," February 15, 2010.
[41] California Statewide Pricing Pilot, 2003-4.
[42] Idaho Power Co., "2006 Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final Report," as quoted in the Edison Electric Institute Report: "Comparison of Results Across Dynamic Pricing and Time-Based Rate Pilot Programs, Appendix E, p.6, January 2008.
[43] Such an approach results in a rather extreme TOU rate, which would probably be unsuitable as a default rate for smaller customers. A 4 to 1 TOU rate design is analyzed in Section X below as a "bookend" TOU case for comparison with a 6 to 1 CPP rate design.

to off-peak TOU price ratios are not possible if a CPP rate is layered on top of the TOU rate, as is the case with PG&E's Peak Day Pricing tariffs. In such combination rate designs, the CPP rate is often set high enough to recover a major portion of the marginal generation capacity costs, leaving little to be recovered through the TOU portion of the tariff. Combination TOU-CPP rates are discussed further in Section XII below.

A second reason why conclusions drawn from Figure 3 or Table 2 may be misleading is that, though CPP programs might yield more demand reduction on a *per participant* basis, the ultimate *number* of participants on TOU programs could be higher. There is much evidence that customers prefer TOU rates to CPP, and hence are more likely to participate in TOU if both programs are voluntary. If CPP is offered on a default basis, many customers are likely to opt-out to non-CPP rate schedules. As will be discussed in Section XI below, almost two-thirds of large industrial customers opted out of PG&E's default CPP rate in 2010 even during the first year that includes bill protection.

A third reason why conclusions drawn from Figure 3 or Table 2 may be misleading is that data from all three large California utilities for the summer of 2010 suggest that large and medium commercial customers, who were placed on CPP *by default,* do not respond as well as indicated by the previous studies cited in the Faruqui-Sergici paper. The 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation, issued by Freeman, Sullivan, and Company states, at page 2, that the average demand responses were only 3.9 percent, 2.8 percent, and 5.26 percent for PG&E, SCE, and SDG&E, respectively. The highest percentage impact observed for any summer 2010 CPP event was 7.2 percent for SDG&E, on August 28, 2010.[44] These values are far below the 13 percent load impact shown as the lower 95 percent confidence bound in Table 2 above (and in Table 16, page 34 of the February 2010 Faruqui-Sergici paper). Demand response results are likely to be even more discouraging if CPP were to be applied to small commercial customers. Again quoting from the Freeman, Sullivan evaluation:

[44] Stephen George, et al., 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation – DRAFT, San Francisco: Freeman, Sullivan & Co., March 24, 2011.

> In addition, the broadest California study on small customer load impacts under dynamic pricing, the California Statewide Pricing Pilot, concluded that small customers did not produce statistically significant load reductions in the absence of enabling technology. (Freeman-Sullivan evaluation, p. 59)

A final reason why conclusions drawn from Figure 3 or Table 2 may be misleading is that the information presented there does not reflect benefits *other than demand response* benefits, such as natural gas power plant fuel cost savings and GHG reduction. Indeed, peak demand reduction is not the "be-all and end-all" of state energy policy. While reducing demand in the top one percent of peak demand hours may allow the retirement of old, inefficient peaker plants and the deferral of the construction of new peakers, the value of top one percent peak reduction has been exaggerated by proponents. Even Dr. Borenstein has acknowledged that the actual cost savings from RTP are modest:

> The results [of RTP simulations] were sobering because as exciting as the prospect of "getting prices right" may be to economists, the potential gains were likely to be only 5 percent or less of the energy bill. And energy is generally only about half of the entire electricity bill, the remainder being transmission, distribution, and customer administration costs. …[U]tilities optimize by building "peaker plants," …capacity that has low capital cost and high operating cost. The social cost of holding idle capacity of this form turns out to be not as great as one might think.[45]

The non-demand response benefits obtainable from time-varying rates are discussed in the next section. These benefits, when included, render the benefits obtainable from TOU comparable to, and potentially superior to, those from CPP.

[45] NBER Reporter: Research Summary 2009 Number 1 Borenstein, S. Electricity Pricing That Reflects Its Real-Time Cost.

Non-Demand Response Benefits of TOU Must be Considered

Summer peak TOU rates are usually effective over many more hours than CPP event hour rates.[46] As a result, TOU rates offer significant secondary benefits beyond demand response. These benefits include:

- Reduction in summer peak period and total energy usage;[47]
- Reduction in the quantity and cost of natural gas power plant fuel consumed;
- Reduction in GHG emissions;
- Increased investment in energy efficiency and customer-owned solar photovoltaic systems (which, in turn, further reduces peak period energy use and GHG emissions);[48] and
- Increased off-peak energy usage which would benefit wind integration.[49]

While both CPP and TOU offer these non-demand response benefits to some extent, these benefits are likely to accrue more to TOU rate designs than to CPP.

[46] The summer peak TOU period usually encompasses about 100 -120 days of the year (600-720 hours) in California, as compared with 9 - 15 days (45-75 hours) for CPP.

[47] Some of the reduction in summer on-peak electricity consumption occurs because usage is merely shifted to other time periods. But the amount shifted tends to be less than the amount reduced during the on-peak period, and thus a reduction in total usage in all summer TOU periods usually also occurs.

[48] The true impact of TOU rates may take several years to measure, and the duration of these studies may be too short to reflect this effect. TOU may be better at incentivizing long-term energy efficiency investments, while CPP may motivate short-term behavioral responses. Unlike TOU, CPP operates during so few hours that customers may respond by avoidance strategies such as closing up shop or, in the case of residential customers, spending the day at an air-conditioned shopping mall. Customers cannot practice avoidance strategies on every summer weekday afternoon, however, and thus demand reduction with TOU rates are best accomplished by installing more efficient appliances and adopting other energy-saving technologies. In fact, the predictable nature of this rate can help customers more easily calculate the saving from instituting such measures.

[49] A robust TOU rate is likely to cause a greater energy usage shift from on-peak to off-peak hours than a CPP rate because of the much greater number of hours over which the peak TOU rate will be effective. The resulting increase in off-peak loads would assist in wind integration as it would enable greater utilization of available nighttime wind energy. For conservatism, Figures 5 through 8 do not include wind integration benefits.

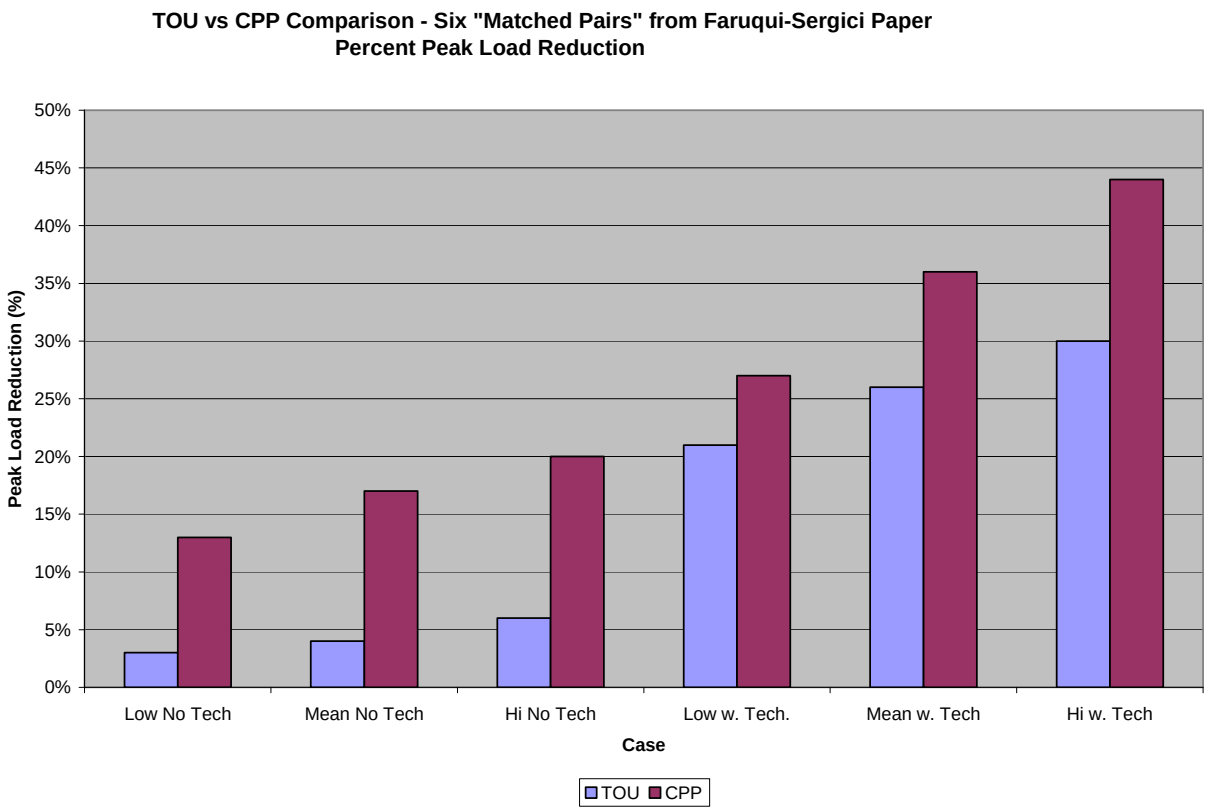

Figure 4 Percent Load Reduction TOU vs. CPP

Table 2 suggests that, absent technology, the peak demand impact for CPP may be 3 to 4 times larger than for TOU. With technology, the differences in demand impact are greatly narrowed. These comparisons are shown graphically in Figure 4, which compares six "matched pairs" of TOU and CPP scenarios suggested by Table 2 above,[50] from the 2010 paper by Faruqui and Sergici.

Even though CPP produces more demand response (as shown in Figure 4), the total summer peak period kWh savings per participant are likely to be greater with TOU than for CPP. This is because the highest TOU rate applies over about ten times as many hours as the highest CPP rate. In other words, a TOU rate design trades off a smaller demand response for a much larger savings in summer peak kWh.

[50] We compare the mean for TOU with the mean for CPP, the 95% lower and upper bounds for TOU with the corresponding bounds for CPP, all without technology; then repeat the comparisons with technology. This yields six pairs of summary statistics for comparison. The demand reduction impacts are shown in Figure 4.

The relative impacts of TOU and CPP on summer peak energy consumption are compared in Figure 5, based on a population of one million customers, where alternatively 30 percent are either on TOU rates or on CPP tariffs.[51] Even though Figure 4 shows that all the CPP scenarios lead to greater MW demand reductions, Figure 5 indicates that the TOU scenarios provide more energy savings.

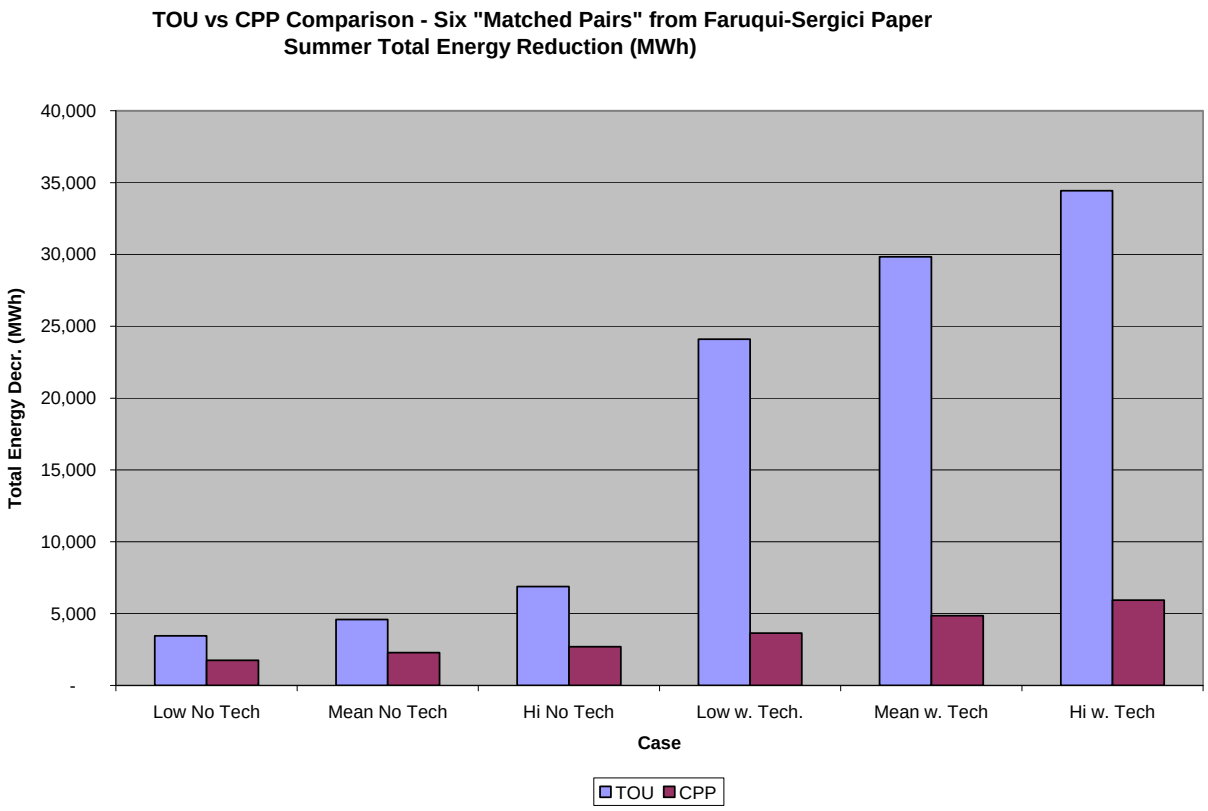

Figure 5 Energy Use Reduction per 300,000 Participants

The following sections compare the reductions in power plant natural gas fuel consumption, GHG emissions, and the monetary value of the capacity, fuel cost, and GHG benefits. The assumptions that underlie this analysis are conservative and are discussed below.

[51] Prior per participant demands of 3 kW and 2.5 kW are assumed for the 60 hour CPP period and 600 hour summer peak period, respectively. These values are roughly representative a hot inland area in Northern California (e.g., PG&E's climate zone "R").

Quantitative Analysis of Benefits Other than Demand Response[52]

Figures 6 and 7 show the impact of TOU energy savings on power plant fuel consumption[53] and GHG emissions. On these two metrics, TOU is clearly superior to CPP. In fact, with technology investments, TOU provides more than five times more reduction in natural gas usage and GHG emissions than does CPP. The results shown in Figures 5 through 7 are based on conservative assumptions:

- As mentioned above, the TOU peak to off-peak price ratios in the 9 TOU studies included in the Faruqui-Sergici paper are modest, and none appears to have a price ratio as high as the 4 to 1 ratio possible if most generation and distribution marginal capacity costs are assigned to the summer peak period.[54]
- 75% of energy reduction in the peak period is assumed to be offset by increased energy consumption in off-peak hours. A lower "rebound effect"[55] would benefit TOU.
- No differential participation rate is assumed, even though evidence suggests that customers prefer TOU (See Section XI below).
- No differential investment in energy efficiency is included.
- No differential wind integration benefit is included.

[52] Results in Figures 5-9 are presented in tabular form in Appendix E, Table A. Appendix E also presents some sensitivity case results.
[53] Marginal generating units are assumed to be fueled by natural gas in all summer hours.
[54] DRA does not necessarily advocate such a rate as a default for smaller customers.
[55] Some PRISM runs for PG&E inland climate zones indicated rebound effects ranging from 40% to 62%. Sensitivities to the size of the rebound effect are presented in Appendix E.

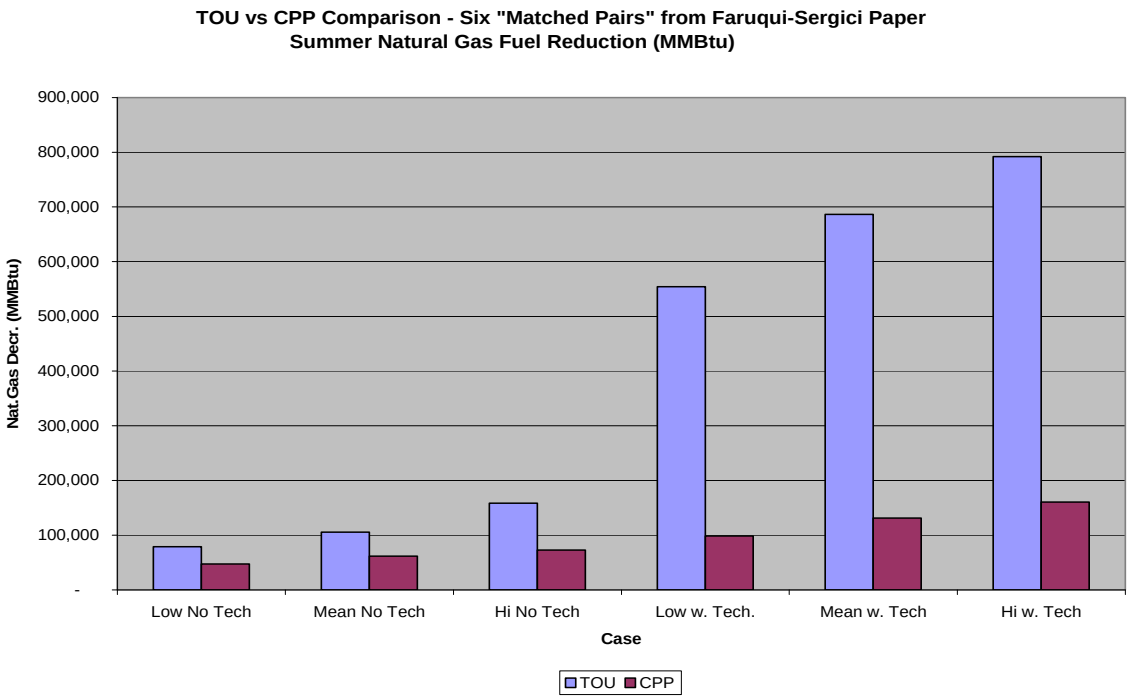

Figure 6: Reduction in Natural Gas Power Plant Fuel Consumption*

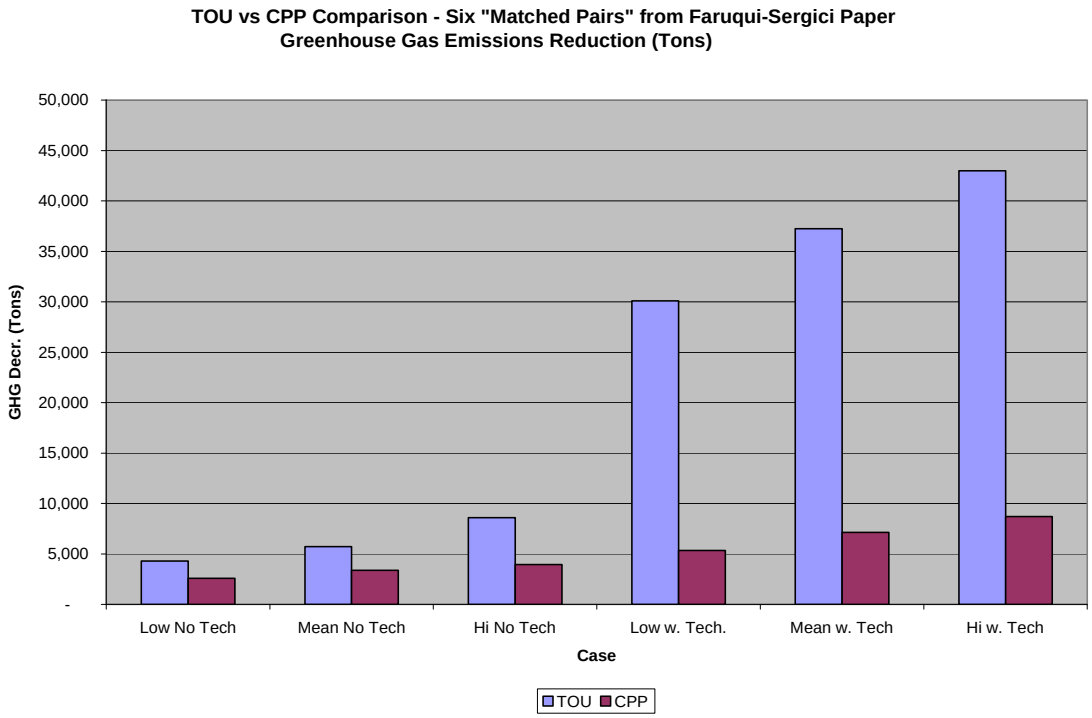

Figure 7: Reduction in GHG Emissions Per Million Customers*

* Based on a population of 1,000,000 customers and a 30% participation rate

As a first cut, it might seem that TOU rates merely shift load from peak to off-peak periods. However, the *net* energy use reduction is usually not zero. For this analysis, it is assumed that 75% of the reduction in energy consumption during peak hours is merely shifted to non-peak hours. The remaining 25% is reflected in a decrease in overall net energy consumption. However, a greater net reduction is possible if, as postulated above, TOU rates induce more investment in energy efficiency than do CPP rates. In that case, TOU would induce a more efficient use of electricity in all hours, in addition to the direct price-related effects discussed above. To be conservative, however, no differential energy efficiency investment is assumed in this example.

It is important to note that, even if the TOU rate design caused a rebound effect of 100%, thus resulting in *no* net change in energy use,[56] there still would be some savings in GHG emissions and generator fuel costs due to the peak/off-peak difference in marginal heat rates and costs.[57]

Cost Implications of Figures 4-7 Results

A dollar valuation of the rate design benefits shown in Tables 4 -7 is shown in Figure 8. This valuation depends upon (1) The avoided cost of generation capacity; (2) The commodity cost of natural gas; and (3) The cost of GHG emissions.

The values assumed for this analysis were (1) $85 per kW-year; (2) $5 per MMBtu; and (3) $20 per ton, respectively. With these inputs, the dollar value of the benefits favors CPP in the first three cases (no technology investment), but favors TOU in the latter 3

[56] Zero net energy usage change might be expected for both TOU and CPP, if revenue neutral, as reductions in peak-hour usage could be offset by increases in off-peak usage. This would not be the case, however, if TOU induces more energy efficiency investment than CPP.

[57] Figures 6 and 7 assume that gas-fired generation is on the margin both on and off-peak and reflect the relative difference in marginal efficiency between peaking and modern base-load generation resources as measured by the heat rate of the marginal generating unit. To the extent gas resources are not on the margin off peak (e.g., due to the availability of marginal night time wind resources), then the GHG emissions reduction would be even greater than those shown in Figure 7. In shifting load from on-peak to off-peak, the same quantity of energy (kWh) can be generated with fewer Btu of natural gas. Since fuel cost and GHG emissions are both proportional to Btu consumed, both are reduced. Marginal heat rate assumptions for Figures 6 and 7 are shown in Appendix D.

comparisons (with technology investments).[58] Other assumptions are given in Appendix D.[59] Sensitivity of benefits to avoided capacity costs and natural gas prices are shown in Appendix E. These sensitivity runs show that the dollar value of the benefits favor CPP in the first three cases and TOU in the last three cases over a wide range of input assumptions.

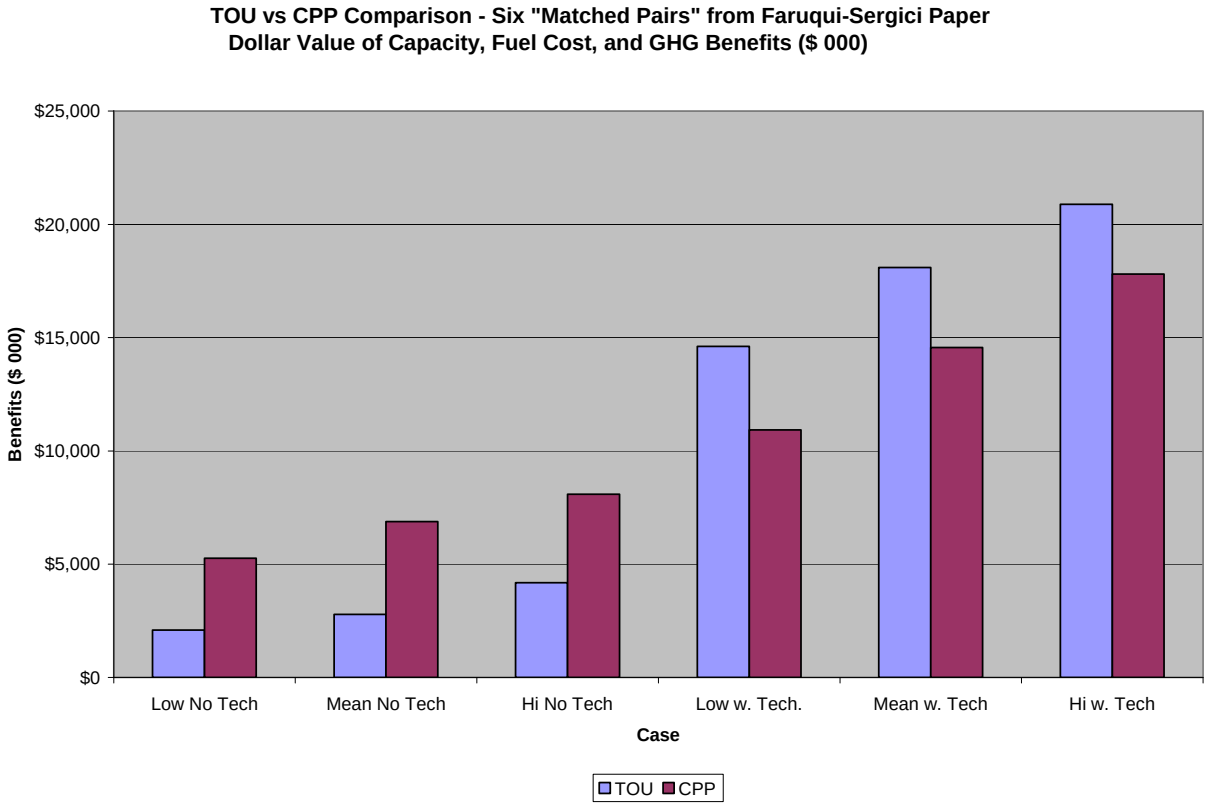

Figure 8 Dollar Value of TOU vs. CPP Benefits per 300,000 Participants

In addition to the effect of technology in narrowing the difference between TOU and CPP (as shown in Figures 3 and 4), the results of Figure 8 reflect a greater value per kW of capacity over a 600 hour peak TOU period as compared to the value per kW over

[58] The results of the 25 TOU and CPP studies described in the February 2010 Faruqui and Sergici paper indicate that introduction of technology benefits TOU more than it does CPP, in terms of increasing demand response.

[59] The values for natural gas prices and avoided capacity costs, used in the above example, are close to those used in PG&E's January 7 Update testimony in the PG&E General Rate Case (Phase 2). A lower avoided capacity cost, however, could be defended on the basis of the large amount of excess generation capacity that currently exists. Also, natural gas prices higher than the $5 per MMBtu value used here could be justified. Just two to three years ago, gas prices were over $10 per MMBtu.

a 60 hour CPP period. These results reflect a proper adjustment of the capacity value to reflect the number of hours over which the program is active.[60]

Sensitivity of TOU and CPP Benefits to Rate Design and Participation

The results shown in Figures 4-8 may not fully reflect the potential net benefits of TOU for at least two reasons: (1) The demand reductions assumed for TOU (based on the Faruqui-Sergici paper) are based on price differentials that are less than those obtainable from fully cost-based TOU rate designs**;** and (2) TOU programs could potentially attract greater customer participation than CPP programs.

Table 3 – Sensitivity of TOU versus CPP Benefits to Participation and Time-Differentiation of Rates

Case No.	Demand response (%)[61]	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
Without Investments in Technology, Response to 4 to 1 TOU Rates per PRISM								
PRISM*a	9.1 TOU	30	82	**41,769**	**10,442**	**244,349**	**13,439**	**$ 6,364**
PRISM*b	**14.5 CPP**	30	131	7,846	1,962	56,100	3,086	$ 5,900
PRISM*c	9.1 TOU	**60**	**164**	**83,538**	**20,885**	**488,697**	**26,878**	**$ 12,727**

Table 3 presents sensitivity results showing the effect of (1) Greater time-differentiation of the TOU rate, and (2) Doubling the TOU participation rate from 30% to 60%. As indicated above, in California, summer peak to off-peak ratios of 4 to 1 are supportable

[60] The most common method for adjusting capacity value to reflect limited hours of availability is to first calculate the loss-of-load probabilities (LOLPs) over each hour of the year, then to normalize them so they all add up to 1.0. Then one sums the normalized LOLPs that fall within the CPP hours as well as the sum that falls within the TOU summer on-peak hours. To DRA's knowledge, Southern California Edison is the only California utility that still maintains an LOLP simulation model. It reported, in its 2008 General Rate Case (Phase 2) that the sum of the normalized LOLP hours in the CPP period is approximately 50 percent. For the TOU summer on-peak period, it is 70 percent. Thus, Table 8 reflects a capacity value of 70% of $85 per kW for the TOU cases and 50% of $85 per kW for the CPP cases.

[61] From residential PRISM model runs for PG&E's hot inland Climate Zone "R." The CPP demand response of 14.53% is based on a 90 cent per kWh event hour CPP adder, with a resulting CPP to non-CPP rate ratio of nearly 6 to 1.

if most generation and distribution marginal capacity costs are assigned to the summer peak period.[62] But such "robust" TOU programs were not included in the Faruqui-Sergici paper. To reflect a "robust" TOU rate design, three additional sensitivity runs were conducted using a PG&E version of the PRISM[63] model for PG&E's climate zone "R," a hot inland area. This model was developed by Dr. Faruqui for use in calculating the demand response benefits of PG&E's Smart Meter system in A.05-06-028 (See Ex. PG&E-4, Ch. 5). Built into this model are the price elasticity estimates that come from the California Statewide Pricing Pilot.

The first sensitivity run, labeled as "PRISM*a," assumes a 9.1% peak demand reduction for TOU, which is above the values shown in Figure 4 for the 3 "no technology" cases but well below the TOU impacts shown for the "with technology" cases.[64] A companion, revenue neutral CPP rate design is shown as case "PRISM*b." The latter case assumes a peak demand reduction of 14.5% based on a comparable PRISM run.[65] Finally, a third scenario, case "PRISM*c" is a TOU case identical to case "PRISM*a," except with a doubled participation rate of 60%. PRISM*a assumes a 40 cent/kWh summer on-peak rate and a 10 cents/kWh summer off peak rate, for an on-peak to off-peak ratio of 4:1. The revenue neutral CPP rate design assumes a CPP rate overlay over a "flat" rate that is not time-differentiated. Thus the total rate is $1.08 /kWh during critical peak events and 18 cents/kWh in all other hours, for a peak to off-peak ratio of 6:1. A mixed TOU-CPP rate design, such as PG&E's PDP, was not analyzed because the objective was to test a pure TOU rate against a pure CPP rate.

When the combined effects of greater participation and greater rate differentiation are taken into account (case PRISM*c of Table 3), the "Robust" TOU program, on a total

[62] For example, PG&E's A-6 rate schedule for small commercial customers has about a 4 to 1 summer peak to off-peak price ratio. Such a rate design is analyzed here for illustrative purposes, but DRA does not advocate such an extremely time-differentiated TOU rate as a default rate for residential or small commercial customers.
[63] The Pricing Impact Simulation Model (PRISM) was originally developed [by Dr. Faruqui] using data derived from the California Statewide Pricing Pilot (SPP) that included some 2,500 residential and small and medium sized commercial and industrial customers during 2003-2005. This information, together with a more complete model description, is contained in an appendix "A Primer on PRISM" to the February 2010 Faruqui-Sergici paper cited above.
[64] The value of 9.1%, derived from the PRISM model, is very conservative relative to the observed reductions in the Faruqui-Sergici paper for TOU with technology (which had a 21% demand reduction at the 95% lower confidence bound).
[65] A CPP adder of 90 cents per kWh was used, resulting in an event hour rate of about $1.08 per kWh, roughly six times the rate in non-event hours.

customer basis, produces more MW of capacity reduction and more dollar benefits than does the CPP program. The results from Cases PRISM*a and PRISM*b, shown graphically in Figure 9, indicate that TOU rates can produce greater physical and monetary benefits for each of the threefold energy goals described at the beginning of this White Paper.

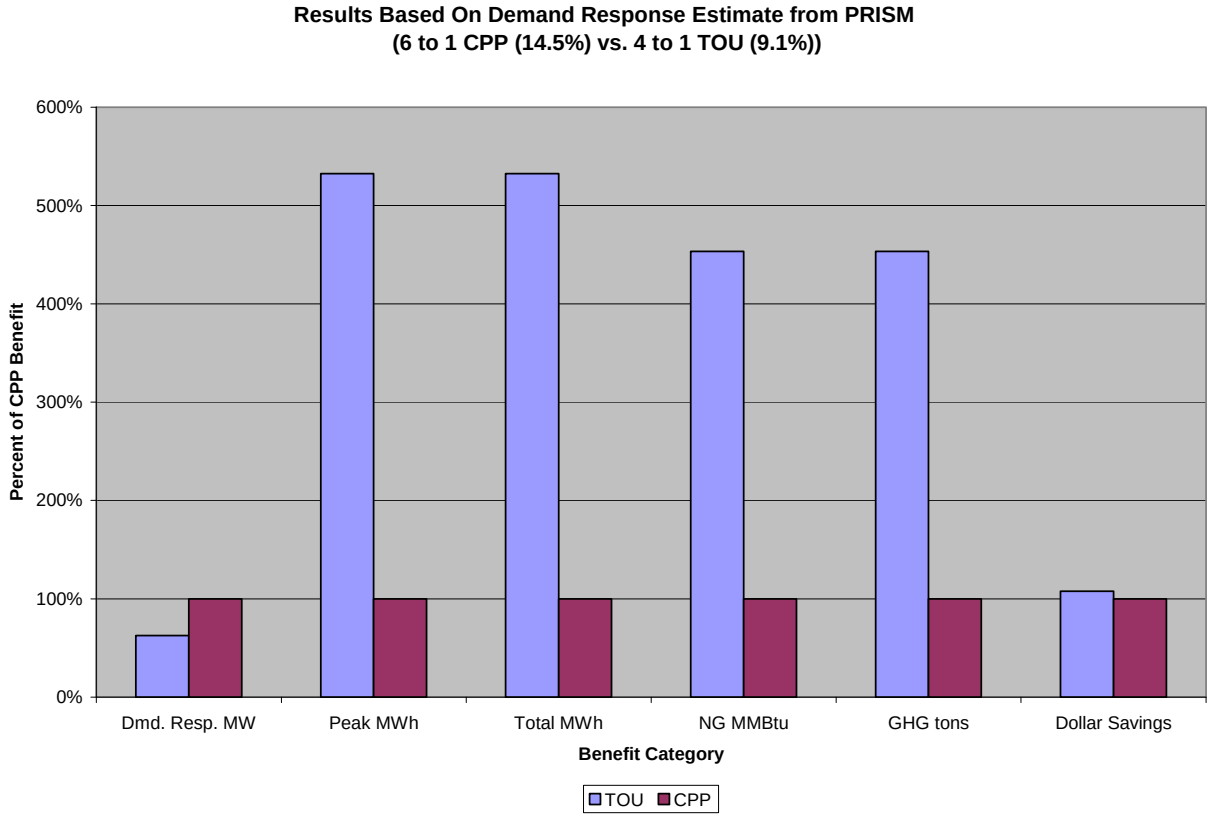

Figure 9 TOU Benefits Relative to CPP Based on PRISM*a and PRISM*b Runs

Summary of Results

The results in Figure 8 could be interpreted as favoring CPP over TOU rates as the best policy tool because technology investments are not required to produce meaningful benefits. However, decision makers must consider four factors:

1. Evidence discussed in the next section might suggest that more customers could be attracted to a milder TOU rate than to CPP, offsetting the smaller benefits per participant.
2. Evidence from the first year of default CPP implementation by the three major California investor-owned utilities does not confirm the expected 13% to 20% demand impact. The actual impacts stated in the March 2011 Freeman-Sullivan report were in the 3% to 7% range.
3. TOU rates produce more dollar value benefits (even on a per participant basis, with technology investment), and given that such investments are likely to occur as customers become familiar with these rates, TOU might be the better long-run option.
4. The current ample availability of generation capacity makes achieving large demand reductions in the short run through CPP less critical.

Figure 9 further suggests that the benefits of TOU rates can be enhanced with a robust TOU rate. But customer participation could be sacrificed if the transition to such aggressive rate designs occurs too rapidly. All these factors indicate the need to transition customers to time-varying rates carefully. It also might be desirable to offer a menu of time-varying rate choices to determine which rate designs will attract the greatest participation. How smaller customers are transitioned to time-varying rates is very critical, and this issue is further discussed in Section XIII below.

Above all, in evaluating the trade-off between CPP and TOU, **decision makers should include fuel cost and GHG emissions cost savings as well as the availability-adjusted value of capacity.** The examples presented above reflect an attempt to use conservative inputs, assumptions, and parameters throughout, which are representative of published results and actual rate designs. **These results, at the very least,**

suggest that further studies of TOU rates are needed. TOU rate designs should be tested that are both well time-differentiated, having peak to off-peak ratios near 3 to 1 or higher, and long lasting, with at least a 3-year duration to test for energy efficiency investment effects.[66]

Especially noteworthy is the fourfold greater aggregate GHG reduction for TOU in some cases, relative to CPP.[67] Given the emphasis placed on climate change (e.g., by AB 32), this is an important result. Consistent with these results, some research does indicate that dynamic rates may be no more effective than TOU rates in reducing GHGs. In reference to a recent paper presented at a conference of the Institute of Electrical and Electronics Engineers (IEEE), Dr. Seth Blumsack stated:

> The main finding of the [IEEE] paper is that from an emissions reduction standpoint, TOU and real-time pricing yield roughly equivalent results. The policy relevance is that while we might like real-time pricing for various reasons, we can use simpler tariff structures if the objective is lowering environmental impacts.[68]

XI: Participation Rates and Customer-Friendliness

The previous sections have discussed how TOU rates can be superior to CPP and RTP rates in terms of generating economic benefits and fulfilling the threefold objectives of California energy policy. However, no discussion of this topic would be complete without considering the customer point of view.

[66] Among other things, TOU rate designs should be tested for their (a) cost impact on various types of customers (including customers in different climate zones), (b) how customers respond to time-varying rates both behaviorally and in terms of making energy efficiency and demand response investments, and (c) customer understanding and acceptance of various rate designs. In addition, more research is required on how to time-differentiate marginal distribution costs. While PG&E's A6-TOU rate assigns most of them to the summer on-peak period, distribution costs are not time-differentiated in any of the utility marginal cost studies filed in General Rate Cases at this time.

[67] Well time-differentiated TOU rates also clearly reduce peak period energy use more than does CPP. Going forward, one must ask whether a greater cost risk to utilities is posed by inefficient energy use and uncontrolled GHG emissions or by returning to the market world of 2000 – 2001. Most people would agree that DP is oriented more towards the latter risk.

[68] S Blumsack, Electric Rate Design and Greenhouse-Gas Emissions Reduction, Power and Energy Society General Meeting, 2009, IEEE.

There is strong anecdotal evidence that customers do not like dynamic rates. The CPUC began a program in the summer of 2010 in which PG&E's large commercial and industrial customers were placed on CPP rates on a default basis, but could "opt-out" to a TOU rate design.[69] A majority of the eligible customers did exactly that, and many of them have opted out before the expiration of the one-year bill protection provision. This significant opt-out rate occurred in spite of an extensive customer outreach program where customer account representatives spoke individually with each customer. Such an outreach effort cannot be cost effectively duplicated for small business and residential customers. Many customers apparently were concerned about the volatility of their bills under a CPP rate design, and also were concerned that they might, on balance, experience bill increases.[70] The statewide opt-out rate during the summer of 2010 for about 15,000, mostly large and medium, commercial customers placed on default CPP was about 53%, with SDG&E having the lowest opt-out rate of 35 percent.[71]

In a non-California example, in 2008 and 2009, Baltimore Gas and Electric Company (BG&E) conducted a large study of CPP and Peak Time Rebate (PTR) rate designs. BG&E found, in 2008, that the two programs were about equally effective, but customers indicated a strong preference for PTR, which does not involve abnormally high rates during high-demand events. Accordingly, BG&E discontinued the CPP trial in 2009.[72]

There are sound reasons why customers prefer TOU to CPP. First, customers like and understand the predictability of TOU rates, which are similar to old "long-distance" telephone rates in that customers could save money by waiting until a preset low-demand period to utilize the service. This is not a new concept to most customers.

[69] As ordered by CPUC Decision 10-02-032.
[70] PG&E, Peak Day Pricing Semi Annual Education and Outreach Assessment Report, December 3, 2010, p.3, p.8. Customers are likely to have the similar concerns about TOU rates with extreme peak to off-peak differentials.
[71] According to the 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation, March 24, 2011 Draft report, issued by Freeman, Sullivan, and Co., (p.7 and P.9) only 7,100 customers remained statewide on CPP rates by the end of summer 2010, out of about 15,000 commercial and industrial accounts defaulted to CPP. For PG&E, only about 1,800 customers remained, out of about 5,000 defaulted. Results do not appear to be stated separately for SCE and SDG&E.
[72] Baltimore Gas and Electric Company, Presentation by Cheryl Hindes, Director of Load Analysis and Settlement, November 5, 2009.

Furthermore, with CPP rates, there is a significant notification issue. Unless customers know when the CPP rates will be implemented, they will grow increasingly frustrated by being charged upwards of $1/kWh. There is no question that CPP will be ineffective unless the notification and customer response process can be automated. But mass marketing of notification equipment to smaller customers may be several years away, and cost will be a significant issue for many customers. Whether customers will be willing to purchase and install such equipment also remains to be seen, and intensive and costly customer outreach and education campaigns may be required for CPP to be successful.

Clearly, customer acceptance must be included in any analysis of CPP versus TOU rate programs. Even if CPP were found to outperform TOU on per-participant metrics, it is unlikely to do so when the greater customer acceptability of TOU is factored in.

XII: Combination TOU-CPP Rate Designs

As adopted for PG&E by the CPUC in a recent dynamic rate decision,[73] PG&E's proposed combination TOU-CPP (a.k.a. PDP[74]) rates could be regarded as an attempt to have the best of both worlds: demand response from the CPP component and an attempt to reduce loads and incent energy efficiency over a broader set of hours via the TOU rate component.

DRA believes that such rates are inferior to a pure TOU approach for the following reasons: (1) Such rate designs are unavoidably complex; and (2) The TOU component of a combination TOU-CPP rate is necessarily less time-differentiated than it would be in a full TOU rate design.

For revenue neutrality, CPP rate designs collect all or a large portion of, marginal generation capacity costs in the roughly 50 – 90 CPP event hours. This leaves little or no generation capacity cost to be collected in the broader (e.g., 600-hour) summer peak

[73] CPUC Decision No. 10-02-032.
[74] Peak Day Pricing.

period. The resulting TOU rates may have peak to off-peak price ratios of 1.5 to 1 or less, and thus have relatively small impact on demand over the broader set of summer peak hours. As indicated before, SCE uses loss-of-load probabilities to allocate generation capacity costs and allocates about 50% of them to the CPP event hours, leaving only about 20% for the remaining summer hours.

In summary, DRA believes that, similar to the conclusion reached in the preceding section, a robust TOU rate design (i.e., with most marginal capacity costs captured in peak periods) would be superior to combination TOU-CPP rates in reducing overall energy usage and GHG emissions.

XIII: Transitioning Small Customers to TOU Rates

DRA is very mindful of the potential adverse bill impacts of a transition to time-varying rates. To mitigate such impacts, it is absolutely essential that such transitions be phased-in gradually and that smaller customers be offered, and educated about, energy efficiency and demand response alternatives.

The "robust" TOU rate design discussed above (case PRISM*a presented in Section X) had a 4 to 1 peak to off-peak ratio.[75] DRA's PRISM runs indicate that such a rate would produce about two-thirds of the demand impact of a 6 to 1 CPP rate design.[76] Based on these results, the TOU rate would have substantially better energy usage and GHG emissions benefits than the CPP rate, primarily because the summer peak TOU rate applies in over ten times as many hours (600) as the CPP rate (60).

While such a "robust" TOU rate may be a desirable end-state for some smaller customers, it is neither necessary nor advisable to transition customers abruptly from non time-varying rates to "robust" TOU rates. DRA strongly recommends that

[75] The TOU rate had a summer peak rate of 40 cents per kWh, roughly equivalent to a Tier 4 residential rate in California. The off-peak (overnight) rate was 10 cents per kWh. DRA does not necessarily advocate such extremely time-differentiated rates as default rates for small customers, but are offered here as an example to "bookend" results achievable from TOU rates.
[76] The CPP rate was $1.08 during 60 CPP hours and an 18 cent rate during all other hours.

TOU pricing be introduced in stages and should start with a less time-differentiated "milder" TOU rate design, perhaps with a peak to off-peak price ratio of 2 to 1 or less.

Further, it is absolutely essential that transitioning to a new rate schedule be preceded and accompanied by adequate customer outreach and education. While such activities are necessary for the success of time-varying rates, they are not sufficient. In addition to education and outreach on the rates, utilities must conduct an aggressive outreach program providing residential and small business customers with an integrated set of energy efficiency and demand reduction solutions through a single point of contact. This is consistent with the Commission's Strategic Plan for Energy Efficiency.[77]

Finally, it may be desirable for utilities to offer multiple TOU rate options to their residential and small business customers. Rate offerings could differ in both the degree of time-differentiation and the timing and duration of peak periods. Such a "pricing portfolio" approach has been successfully employed in Arizona, in the Salt River Project.[78]

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[77] In its *Energy Efficiency Strategic Plan*, the Commission identified the lack of integrated solutions as a critical problem for utility customers. The Commission stated:

> Historically, demand side management (DSM) options for energy consumers have been "siloed" activities within regulatory bodies, utilities, environmental organizations, and among private sector service providers. The programs are focused on mass delivery and promotion of individual products, for example efficient air conditioners, rather than on integrated packages of measures, for example, air conditioner rebates with duct sealing, weather-stripping, programmable thermostats, and advanced meters. This current narrow focus on a single product offering does not maximize energy savings nor minimize the costs of program delivery.
>
> A narrow, single-product approach also results in customer confusion by requiring the customer to seek out information on a wide array of different programs with multiple points of contact in order to acquire a basic understanding of the DSM options available and the various benefits they offer. Most energy users across all economic sectors do not have the time or expertise to seek this information; as a result, many opportunities to accomplish DSM actions are lost. (*Energy Efficiency Strategic Plan: Achieving Maximum Energy Savings in California For 2009 and Beyond*, California Public Utilities Commission, September 2008, p. 71.)

Given these problems, the Commission makes it a goal to "Deliver integrated DSM options that include efficiency, demand response, energy management, and self generation measures through coordinated marketing and regulatory integration." (*Id.*, p. 72.) The Commission goes on to state, "***Outreach and consumer education, and DSM program options must be offered in a unified fashion so that energy users receive complete DSM information with minimum effort, preferably through single points of contact."*** (*Id.,* emphasis added.)

[78] See presentation, "EZ-3 Residential TOU Price Plan" by Loren Kirkeide, Salt River Project, November 5, 2009. As Mr. Kirkeide explains, the effect of multiple TOU options is likely to be better than any single option and, by taking advantage of variation in individual preferences, is likely to increase customer satisfaction.

XIV: Conclusion

This paper reaches the following conclusions:

- TOU pricing is more understandable and places fewer burdens on customers than dynamic pricing. More customers are likely to participate in voluntary or default TOU programs than in voluntary or default CPP programs.
- Dynamic pricing is only one of several means of achieving demand response; TOU pricing also contributes to demand response and may be more cost effective than CPP when other benefits are included.
- Like dynamic pricing, TOU pricing utilizes the time-variant pricing capability of AMI; TOU rate design may actually confer better overall usage reduction and GHG reduction benefits than dynamic pricing.
- Due to the ample generating capacity and lack of scarcity provided by Resource Adequacy and other CPUC policies that encourage investment in new generation capacity, hourly California wholesale market prices are no longer volatile. Thus, hourly prices cannot provide the price signal hoped for by RTP proponents.
- TOU rate design is more likely than CPP to encourage investment in energy efficiency. This could be a major factor in the superiority of TOU to CPP in achieving California energy policy goals of reducing GHG emissions and controlling cost.
- TOU rates would, by increasing electric system load factors, make California's electric system more efficient and hold down future increases in the cost of electric energy.
- Finally, TOU rates could help the overall residential and small business customer classes by (1) Slowing the growth of utility revenue requirements; and (2) Reducing these classes' share of revenue requirements. The residential and small business classes, as a whole, could experience lower bills if TOU rates were widespread.

For all these reasons, the Commission should reconsider its rate design policy and move away from default CPP for smaller customers. Instead, it should encourage most

customers, including residential and small commercial customers, to be on TOU rates. Because TOU pricing will be a significant change in how residential and small commercial customers are charged for electricity, rate designs should be tested and carefully implemented. Transition to time-varying rates should be preceded and accompanied by adequate customer outreach and education, including an aggressive program providing residential and small business customers with an integrated set of energy efficiency and demand reduction solutions through a single point of contact.

Appendix A
Energy Action Plan II

California Demand Response: A Vision for the Future

(2002-2007)

Joint statement for consideration by the California Energy Commission, Public Utilities Commission, and Consumer Power and Conservation Financing Authority.

This vision is intended as a broad statement for encouraging demand responsiveness in California. It should be read in the context of maximizing the efficient use of resources, while maintaining the economic vitality of businesses in the state, as well as the health, welfare, and comfort of residential electricity users.

We acknowledge that demand response is one resource among many that may be procured by utilities on behalf of their electricity customers. We also seek to make the most cost-effective investments in demand response from an overall societal perspective.

Finally, this vision is intended as a starting point, and should not be interpreted as prejudging the outcome of analysis and recommendations delivered by the working groups to the policymakers in this proceeding. Further, we intend to use this vision as a guide to our efforts, will continue to reevaluate its validity and assumptions as we progress, and will make any modifications, as necessary and appropriate, when new information becomes available.

Definition

DEMAND RESPONSE gives an individual electric customer the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal.

Vision

All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by no later than 2007.

Objectives

Reliability

- Timely demand response (within minutes or hours) from customers can offset the need for investment in generation, transmission, and/or distribution.
- Demand response activities should be designed to achieve a target of 5% reduction in peak demand by 2007.

- Cost-effective demand response should be used to meet a portion of reserve requirements.
- Numerous and diverse customers voluntarily reducing or shifting their demand in response to economic signals is preferable to controlled outages during power system emergency situations.

Lower Power Costs

- During high-cost periods, demand response can assist in bringing supply and demand into balance by signaling to the consumer the actual costs of buying power at the margin and/or investing in new power resources, thereby lowering overall wholesale electricity costs for all customers.
- Timely demand response can, along with other wholesale market measures, help mitigate wholesale market power and ensure reasonable prices.
- To encourage demand response, a long-term objective is designing retail rates that dynamically incorporate the marginal cost of providing electricity service.
- Demand response activities and infrastructure should be designed to be cost-effective from a societal perspective.

Environmental Protection

- Reducing consumer electricity usage during peak periods can help reduce fuel use and therefore overall air emissions by reducing output from marginal generation units.
- The agencies' definition of demand response does <u>not</u> include or encourage switching to use of fossil-fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads.

Goals and Principles

Customer Service

- Electric consumers in California should be made aware of the time-variable nature of electricity costs and of general steps they can take to help lower those costs.
- All customers that desire it should have greater access to information about their own electricity use, at least weekly or daily, with the option for hourly or more frequent data.
- Technologies to enable demand response may also provide other customer service benefits including outage detection and management, power quality management, and other information capabilities.
- Demand response programs and tariffs should be designed to be customer-friendly, simple, and easy to understand, as well as to minimize customer confusion and allow for continuity among options.

Optionality

- Customers should have the ability to choose voluntarily among various tariff options, including:
    - Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time-of-Use (TOU) Pricing
    - Large customers (200 kW to 1 MW): CPP, TOU, or RTP
    - Residential and small commercial customers (under 200 kW): CPP, TOU, or flat rate (the latter with an appropriate hedge for risk protection)
- Customers should also have the option to participate voluntarily in programs where they are paid to provide demand reduction as a dispatchable resource, including:
    - In ISO markets: real-time, hour ahead, day ahead, ancillary services, planning reserves
    - In retail markets: such programs as direct load control, including air-conditioner or water pump cycling, and controllable thermostats.

Technologies

- All customers should be provided an advanced metering system capable of supporting a TOU tariff or better, if cost-effective, and with minimal hardware upgrades necessary to choose among various dynamic tariffs.
- All customers who choose to should be able to conveniently access their usage information using communications media (e.g., over the internet, via on-site devices, or other means chosen by the customer and respectful of potential privacy concerns).
- The broadest possible range of metering and communications technologies that can enable demand response should be encouraged (i.e., optionality), but all technologies should be compatible with utility billing and other back-office systems.
- State building code (Title 24) updates provide a cost-effective opportunity to introduce demand response technologies during the construction of new buildings or renovation of existing buildings.

Investor-Owned Utility (IOU) Issues

- IOUs should be reimbursed for all reasonable expenditures on infrastructure and administration to enable demand response.
- IOUs should be required to procure demand response resources as a portion of their overall procurement portfolio (target of 5% of peak demand by 2007) and as a portion of their reserve requirements beginning in 2004.
- IOUs should also be provided an incentive mechanism to encourage the best choices for ratepayers.

- Operation of an IOU's overall demand response portfolio should be designed to collect the approved revenue requirement and be revenue neutral to the IOU (e.g., revenues stay consistent with costs), with periodic true-ups as necessary.
- All IOU demand response efforts should be periodically evaluated to determine past performance and improve future effectiveness.

Coordination Issues

- Effective demand response efforts will require coordination among the agencies promulgating this vision statement, as well as the California Independent System Operator (ISO) and the California Legislature.

  Coordination will also be necessary related to:

  - IOU procurement planning
  - IOU rate design modifications, either in general rate cases or separate venues
  - Energy Efficiency (and other public purpose) programs
  - Other peak demand reduction programs
  - ISO efforts to develop transparent wholesale market pricing mechanisms
  - Legislative reports such as required by SB1976 and Public Utilities Code Section 393
  - Necessary legislative change to rationalize rate design structures

    by the end of 2006

Appendix B
Brief Overview of Dynamic Pricing

Dynamic Pricing

A dynamic rate schedule is one in which prices are responsive to system conditions. Either the price itself, the timing of that price, or neither can be fully predetermined at the time the tariff goes into effect. Thus the price and/or the timing are unknown until real-time system conditions warrant a price adjustment. System conditions are defined as any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.

Examples of dynamic pricing include real-time pricing (RTP) and critical peak pricing (CPP).

Dynamic rates are a form of demand response, defined as providing the financial incentive to an individual electric customer to reduce or shift usage or demand. In the case of dynamic rates, the incentive is a short-term change in the rate (retail price) of electricity. However, other forms of demand response programs exist in which customers respond to financial incentives other than rates.

CPP Rates

These are dynamic rates that allow a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. In a fixed-period CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a variable-period CPP, the time, duration and day of the price increase are not predetermined.

Unlike TOU rates, which typically have a summer peak period of about 720 hours, CPP rates are typically active for only 36-60 hours per year.[79]

[79] Based on PG&E CPP rate designs which allow 9 to 15 event days and 4 hours per event.

RTP Rates

This is a dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions, defined as any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.

While the concept of RTP rates may be theoretically appealing, there is no real-time wholesale market price in California that reflects a market that simultaneously includes energy and capacity. Thus, with RTP, the devil is in the details in that it is not at all clear how to implement RTP. Nor is it apparent that the rate can be implemented in a manner that would provide the benefits claimed by proponents of dynamic pricing.

Further Findings of Professor Borenstein With Respect To RTP

Dr. Borenstein acknowledges,[80] however, that there has been much debate about RTP, and two concerns merit further empirical study: (1) Many customers perceive, perhaps inaccurately, RTP will increase their overall energy bills, and (2) RTP will make their energy bills more volatile:

> The industry and public policy debate about RTP in the years following the California electricity crisis brought out a broad range of producer and customer concerns about RTP. …[T]wo concerns, in particular, merited further empirical study.
>
> First, some customers would be winners and others losers with a switch to RTP. Those who consume disproportionate quantities at the most expensive times are being subsidized under time-invariant pricing and may be worse off if they cannot adjust their consumption substantially under RTP. Most energy managers in industrial and commercial customers seemed to think that their bills on average would rise significantly under RTP (even though total system costs would fall with the switch). Second, even customers who thought their consumption pattern

[80] NBER Reporter: Research Summary 2009 Number 1, Borenstein, S., Electricity Pricing That Reflects Its Real-Time Cost. The italicized text in the following excerpts are not italicized in Borenstein's original article.

was no more expensive to supply than the typical customer were still worried that their bills could be much more volatile under RTP.

The results [with simulated and actual wholesale prices[81]] made clear that extremely few customers would see disruptive changes in their electricity bills, but that there would be a significant number of small losers.

Using the same dataset, I studied bill volatility under RTP. Bill volatility is caused by consumption volatility, price volatility, and the covariance of the two. In electricity, departures from average consumption quantity and average real-time price tend to be positively correlated, exacerbating the variance of bills. Using monthly billing periods, I calculated customer bills under time-invariant, time-of-use, and real-time pricing schemes. After adjusting for seasonal variation, which should be easy to anticipate, I found that the coefficient of variation of a customer's bill is on average nearly five times larger under RTP than under the time-of-use structure that they typically face.

[81] Based on hourly consumption data for 1142 large industrial and commercial customers in Northern California.

Appendix C
Glossary of Terms

Automatic Control Technology	Any technology that allows the customer or electric service provider to pre-program a control strategy - for an individual electric load, group of electric loads, or an entire facility - to be automatically activated in response to a dispatch.
Critical-Peak Pricing (CPP)	A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. In a fixed-period CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a variable-period CPP, the time, duration, and day of the price increase are not predetermined.
Demand Rate	A per-kW rate, typically applied to the peak demand during each month.
Demand Response	The ability of an individual electric customer to reduce or shift usage or demand in response to a financial incentive.
Dispatch	A broadcast signaling the initiation of a control strategy or price adjustment.
Dynamic Rate	A rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. Examples: real-time pricing (RTP), critical peak pricing (CPP).
Flat Rate	A per-kWh rate in which the same price is charged for all hours during a predetermined time period, usually a season or year.
Information	Facts and data that facilitate consumer response to energy prices. "Basic information" describes a tariff and its potential impact on expected monthly energy costs. "Technical information" describes technologies that can be used to respond to the tariff. "Energy information" describes the consumer's energy consumption

	patterns, on an ongoing basis, to help the consumer adjust behavior and infrastructure to reduce monthly energy costs.
Interval Meter	An electricity meter or metering system that records a consumer's load profile by storing in memory each consecutive demand interval, which typically consists of a period ranging from 5 minutes to an hour, synchronized to the hour. The meter can be read through a hand-held device (typically monthly) or through a data link to a central metering master station (typically daily).
Notification	Information provided to customers regarding price adjustments or system conditions. "Day-ahead" notification provides at least 24 hours advance notice. "Hour-ahead" notification provides at least one hour advance notice.
Price Elasticity	A measure of the sensitivity of customer demand to price. Price elasticity is expressed as the ratio of the percent change in demand to the percent change in price; e.g., a 10% load drop in response to a 100% price increase yields a price elasticity of -0.10. "Own-price" elasticity relates changes in peak period demand to changes in peak period price. "Cross-price" elasticity relates changes in usage in one period to changes in price in another period.
Rate	The retail price of electricity per-kW demand or per-kWh usage. A rate may vary as a function of usage (tiered rate), demand (demand rate), period of use (time-of-use rate), or as a function of system conditions (dynamic rate).
Real-Time Pricing (RTP) Rate	A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.
Revenue Neutrality	A regulatory requirement that any alternative rate design must recover the same total revenue requirement as the default rate design, assuming that customers make no change in their usage patterns.
Seasonal Rate	A rate in which the price of electricity changes by season.
Smart Thermostats	A heating, ventilation, and air-conditioning (HVAC) thermostat that: (1) Automatically responds to different electricity prices by

	adjusting the temperature set point or the operation of the HVAC equipment using pre-programmed thresholds that have been specified by the customer; (2) Displays energy information and rates, and notifies the customer of rate changes; and/or (3) Can be programmed to control devices other than the HVAC system.
System Conditions	Any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.
Tariff	A public document setting forth the services offered by an electric utility, rates and charges with respect to the services, and governing rules, regulations and practices relating to those services.
Tiered Rate	A rate in which predetermined prices change as a function of cumulative customer electricity usage within a predetermined time frame (usually monthly). Prices in an "inverted tier" rate increase as cumulative electricity usage increases. Prices in a "declining tier" or "declining block" rate decrease as cumulative electricity usage increases.
Time-Of-Day (TOD) Rate	A rate in which predetermined electricity prices vary across two or more pre-set time periods within a day.
Time-Of-Use (TOU) Rate	A rate in which the price of electricity varies as a function of usage period, typically by time of day, by day of week, and/or by season. Examples: TOD rate, seasonal rate.
Time-Varying Rate	A rate in which prices change or can be changed within a 24-hour period. Examples: TOD rate, dynamic rate.

Appendix D
Common Assumptions for Figures 5-9 of Section X

TOU vs. CPP: Physical and Economic Input Assumptions

Common Model Inputs

Res customer flat rate usage						
Peak			Peak Usage Per			
hour			Day			
KW						
	Summer					
2.5	Summer Pk.					
3	**Crit. Pk.**					
	Off-peak rebound		**75%**			
Marginal generator heat rate						
		11,000	Btu/kWh (summer normal peak)			
		12,000	Btu/kWh (critical peak)			
		7,000	Btu/kWh (off peak-- NO WIND)			
		7,000	**Btu/kWh (off peak-- With WIND)**			
	WIND	**0%**	**of off-peak marginal generation**			
Cost Parameters						
Nat. Gas	$5.00		per MMBtu			
Carbon	$1.09		per MMBtu	@	$20	per ton
Capacity	**$85**		**per kW-year**			
LOLP						
fac.	50%		60 hour CPP period			
	70%		600 hour TOU summer peak period			

CPP and Average summer peak demands are roughly representative of a hot inland area in Northern California (PG&E Climate Zone "R").

Marginal generator heat rates are approximate estimates based on analysis of 2010 California Energy Commission generator data from the CEC's spreadsheet that shows all the generators heat rates:
http://energyalmanac.ca.gov/electricity/web_qfer/Heat_Rates.php

The $85 per kW-yr avoided cost of generation capacity is a reference value that was used in the California IOU's "business cases" in support of AMI. This value was adjusted in this paper by applying factors of 50% (CPP) and 70% (TOU) reflecting the limited number of hours over which each of these resources are available. These factors come from a Southern California Edison analysis of its hourly generator loss of load probability (LOLP) presented in its 2008 General Rate Case.[82]

High and low capacity value sensitivity cases are included in Appendix E.

[82] A.07-07-026, Ex. SCE-4, Appendix B., pp.B-17 to B-20.

Appendix E

Sensitivity of TOU and CPP Benefits to Capacity and Energy Costs, Rebound Effects, and Availability of Off-Peak Wind Energy

Table A encapsulates the results presented in Figures 4 through 9 of Section X. Tables B and C repeat the TOU and CPP cases shown in Table A respectively, under the following cost assumptions: (I) $120 per kW-year (capacity) and $5.00 per MMBtu (energy); (II) $32 per kW-year (capacity) and $10.00 per Btu (energy).[83] Tables D and E present sensitivities to the "rebound effect." Table F presents a sensitivity to the availability of off-peak wind energy.

Table A – Benefits of TOU versus CPP Scenarios per Million Eligible Customers

(Capacity: $85 per kW-year; Natural Gas: $5.00 per MMBtu; 75% Rebound)

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
				Without Investments in Technology				
0 TOU-L	3	30	27	**13,770**	**3,443**	**79,178**	**4,298**	$2,088
0 CPP-L	**13**	30	**117**	7,020	1,755	47,385	2,572	**$5,261**
1 TOU-M	4	30	36	**18,360**	**4,590**	**105,570**	**5,731**	$2,784
1 CPP-M	**17**	30	**153**	9,180	2,295	61,965	3,364	**$6,880**
2 TOU-H	6	30	54	**27,540**	**6,885**	**158,355**	**8,596**	$4,177
2 CPP-H	**20**	30	**180**	10,800	2,700	72,900	3,957	**$8,094**
				With Investments in Technology				
3 TOU-L	21	30	189	**96,390**	**24,098**	**554,243**	**30,088**	**$14,618**
3 CPP-L	**27**	30	**243**	14,580	3,645	98,415	5,343	$10,926
4 TOU-M	26	30	234	**119,340**	**29,835**	**686,205**	**37,251**	**$18,099**
4 CPP-M	**36**	30	**324**	19,440	4,860	131,220	7,123	$14,569
5 TOU-H	30	30	270	**137,700**	**34,425**	**791,775**	**42,982**	**$20,884**
5 CPP-H	**44**	30	**396**	23,760	5,940	160,380	8,706	$17,806

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

[83] It should be noted that Tables B and C assume the same rate designs as are incorporated into the other tables even though a modification of gas prices and capacity costs could impact the rate designs themselves. In particular, reducing the avoided capacity cost by two thirds should theoretically lead to lower CPP charges and reduced on-peak to off-peak ratios in TOU rates. However, given that the Faruqui-Sergici paper tested TOU rates that were rather mild to begin with, DRA did not see the need to reduce the demand reductions shown in that study even further to reflect what would be achieved with even smaller CPP charges and milder TOU rates.

Table B – Benefits of TOU versus CPP Scenarios per Million Eligible Customers
(Capacity: $120 per kW-year; Natural Gas: $5.00 per MMBtu; 75% Rebound)

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
				Without Investments in Technology				
0 TOU-L	3	30	27	**13,770**	**3,443**	**79,178**	**4,298**	$2,750
0 CPP-L	**13**	30	**117**	7,020	1,755	47,385	2,572	**$7,308**
1 TOU-M	4	30	36	**18,360**	**4,590**	**105,570**	**5,731**	$3,666
1 CPP-M	**17**	30	**153**	9,180	2,295	61,965	3,364	**$9,557**
2 TOU-H	6	30	54	**27,540**	**6,885**	**158,355**	**8,596**	$5,500
2 CPP-H	**20**	30	**180**	10,800	2,700	72,900	3,957	**$11,244**
				With Investments in Technology				
3 TOU-L	21	30	189	**96,390**	**24,098**	**554,243**	**30,088**	**$19,249**
3 CPP-L	**27**	30	**243**	14,580	3,645	98,415	5,343	$15,179
4 TOU-M	26	30	234	**119,340**	**29,835**	**686,205**	**37,251**	**$23,832**
4 CPP-M	**36**	30	**324**	19,440	4,860	131,220	7,123	$20,239
5 TOU-H	30	30	270	**137,700**	**34,425**	**791,775**	**42,982**	**$27,499**
5 CPP-H	**44**	30	**396**	23,760	5,940	160,380	8,706	$24,736

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

Table C – Benefits of TOU versus CPP Scenarios per Million Eligible Customers
(Capacity: $32 per kW-year; Natural Gas: $10.00 per MMBtu; 75% Rebound)

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
Without Investments in Technology								
0 TOU-L	3	30	27	**13,770**	**3,443**	**79,178**	**4,298**	$1,483
0 CPP-L	**13**	30	**117**	7,020	1,755	47,385	2,572	**$2,397**
1 TOU-M	4	30	36	**18,360**	**4,590**	**105,570**	**5,731**	$1,977
1 CPP-M	**17**	30	**153**	9,180	2,295	61,965	3,364	**$3,135**
2 TOU-H	6	30	54	**27,540**	**6,885**	**158,355**	**8,596**	$2,965
2 CPP-H	**20**	30	**180**	10,800	2,700	72,900	3,957	**$3,688**
With Investments in Technology								
3 TOU-L	21	30	189	**96,390**	**24,098**	**554,243**	**30,088**	**$10,378**
3 CPP-L	**27**	30	**243**	14,580	3,645	98,415	5,343	$4,979
4 TOU-M	26	30	234	**119,340**	**29,835**	**686,205**	**37,251**	**$12,849**
4 CPP-M	**36**	30	**324**	19,440	4,860	131,220	7,123	$6,639
5 TOU-H	30	30	270	**137,700**	**34,425**	**791,775**	**42,982**	**$14,825**
5 CPP-H	**44**	30	**396**	23,760	5,940	160,380	8,706	$8,114

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

Table D – Benefits of TOU versus CPP Scenarios per Million Eligible Customers (Capacity: $85 per kW-year; Natural Gas: $5.00 per MMBtu; 100% Rebound[84])

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
Without Investments in Technology								
0 TOU-L	3	30	27	**13,770**	**-**	**55,080**	**2,990**	$1,942
0 CPP-L	**13**	30	**117**	7,020	-	35,100	1,905	**$5,186**
1 TOU-M	4	30	36	**18,360**	**-**	**73,440**	**3,987**	$2,589
1 CPP-M	**17**	30	**153**	9,180	-	45,900	2,492	**$6,782**
2 TOU-H	6	30	54	**27,540**	**-**	**110,160**	**5,980**	$3,883
2 CPP-H	**20**	30	**180**	10,800	-	54,000	2,931	**$7,979**
With Investments in Technology								
3 TOU-L	21	30	189	**96,390**	**-**	**385,560**	**20,931**	**$13,592**
3 CPP-L	**27**	30	**243**	14,580	-	72,900	3,957	$10,771
4 TOU-M	26	30	234	**119,340**	**-**	**477,360**	**25,914**	**$16,828**
4 CPP-M	**36**	30	**324**	19,440	-	97,200	5,277	$14,362
5 TOU-H	30	30	270	**137,700**	**-**	**550,800**	**29,901**	**$19,417**
5 CPP-H	**44**	30	**396**	23,760	-	118,800	6,449	$17,553

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

[84] This scenario assumes no net energy reduction: peak savings are fully offset by off-peak increases.

Table E – Benefits of TOU versus CPP Scenarios per Million Eligible Customers (Capacity: $85 per kW-year; Natural Gas: $5.00 per MMBtu; 50% Rebound[85])

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
				Without Investments in Technology				
0 TOU-L	3	30	27	**13,770**	**6,885**	**103,275**	**5,606**	$2,235
0 CPP-L	**13**	30	**117**	7,020	3,510	59,670	3,239	**$5,336**
1 TOU-M	4	30	36	**18,360**	**9,180**	**137,700**	**7,475**	$2,980
1 CPP-M	**17**	30	**153**	9,180	4,590	78,030	4,236	**$6,977**
2 TOU-H	6	30	54	**27,540**	**13,770**	**206,550**	**11,213**	$4,470
2 CPP-H	**20**	30	**180**	10,800	5,400	91,800	4,983	**$8,209**
				With Investments in Technology				
3 TOU-L	21	30	189	**96,390**	**48,195**	**722,925**	**39,245**	**$15,645**
3 CPP-L	**27**	30	**243**	14,580	7,290	123,930	6,728	$11,082
4 TOU-M	26	30	234	**119,340**	**59,670**	**895,050**	**48,589**	**$19,370**
4 CPP-M	**36**	30	**324**	19,440	9,720	165,240	8,970	$14,776
5 TOU-H	30	30	270	**137,700**	**68,850**	**1,032,750**	**56,064**	**$22,350**
5 CPP-H	**44**	30	**396**	23,760	11,880	201,960	10,964	$18,059

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

[85] This scenario assumes 50% of peak energy reduction is offset by increases in off-peak consumption.

Table F – Benefits of TOU versus CPP Scenarios per Million Eligible Customers (Capacity: $85 per kW-year; Natural Gas: $5.00 per MMBtu; 75% Rebound[86]) (20% Off-Peak Wind Energy Availability[87])

Case No.	Demand response (%)	Cust. Particip. (%)	MW reduction (MW)	Peak kWh reduced (Mwh)	Total kWh reduced (Mwh)	N.G. Btu reduction (MMBtu)	GHG reduction (tons)	Dollar Benefits $ 000
Without Investments in Technology								
0 TOU-L	3	30	27	**13,770**	**3,443**	**93,636**	**5,083**	$2,176
0 CPP-L	**13**	30	**117**	7,020	1,755	54,756	2,972	**$5,306**
1 TOU-M	4	30	36	**18,360**	**4,590**	**124,848**	**6,777**	$2,902
1 CPP-M	**17**	30	**153**	9,180	2,295	71,604	3,887	**$6,938**
2 TOU-H	6	30	54	**27,540**	**6,885**	**187,272**	**10,166**	$4,353
2 CPP-H	**20**	30	**180**	10,800	2,700	84,240	4,573	**$8,163**
With Investments in Technology								
3 TOU-L	21	30	189	**96,390**	**24,098**	**655,452**	**35,582**	**$15,234**
3 CPP-L	**27**	30	**243**	14,580	3,645	113,724	6,174	$11,020
4 TOU-M	26	30	234	**119,340**	**29,835**	**811,512**	**44,054**	**$18,862**
4 CPP-M	**36**	30	**324**	19,440	4,860	151,632	8,231	$14,693
5 TOU-H	30	30	270	**137,700**	**34,425**	**936,360**	**50,831**	**$21,763**
5 CPP-H	**44**	30	**396**	23,760	5,940	185,328	10,061	$17,958

L: 95% lower confidence bound; M: mean; H: 95% upper confidence bound

[86] This scenario assumes 75% of peak energy reduction is offset by increases in off-peak consumption.
[87] This scenario assumes that wind generation is on the margin during 20% of off-peak hours, at zero marginal cost.