Toward a New Paradigm for Valuing Demand Response

There is value in DR, but it needs to be evaluated correctly. The pricing experiment in California showed that well-designed dynamic pricing programs can have a significant impact on critical peak loads, and California's investor-owned utilities are using the experimental results to develop business cases for advanced metering. A key question in developing these business cases is how much value to attach to a kW of load that is curtailed during critical times.

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I. Introduction

It is well known that the lack of demand response (DR) was one of the contributing factors in the California energy crisis, a watershed event in the history of the U.S. electricity industry.[1] Following the crisis, many conferences were held on the role of DR and a torrent of articles, papers, and reports on the matter were produced in the years that followed. Several states, mostly on the two coasts, implemented a variety of DR programs, some of which exploited innovations in pricing design while others used cash rebates to lower demand during peak periods.

Most of the new pricing designs involved a dynamic element of ''callability'' that was superimposed on top of a time-of-use (TOU) rate. In other words, customers were notified on a day-ahead or hour-ahead basis that prices were going to rise. Such pricing designs came to be known as dynamic pricing and

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included critical-peak pricing (CPP), where the higher prices were known ahead of time but their timing was uncertain, and real-time pricing (RTP) designs, where both the timing and price were uncertain.

In the years since the California crisis, many myths have grown around the role DR can play in averting energy crises and lowering customer bills, with some arguing that it can eliminate the need for expanding power generation and delivery capacity while others say its benefits are elusive, cannot be quantified, and cannot be counted upon during a real crisis. One of the big questions is how to value DR.

II. How Does DR Create Value?

DR can provide benefits in a variety of ways, such as reducting the need for peak capacity, improving system reliability, reducing the consumption of energy, and reducing externality costs. It is, of course, important in measuring the value of DR to actually capture all of the different benefits that DR provides. Some current regulatory practices, such as the California Standard Practice Manual (SPM) that has been adapted nationwide, do not fully account for DR benefits.[2] However, it is also important to not unfairly favor DR in determining the value of its benefits, as has been proposed by a number of DR enthusiasts.

The benefits from DR mainly come from two of the sources mentioned above. First, DR can reduce the consumption of electrical energy and result in savings due to lower fuel consumption and variable operating expense from the operation of power plants. When the reduction of the consumption of electrical energy occurs is important, however, because the reduction of energy consumption on peak provides more value than off-peak reduction since on-peak supply costs are greater than those off-peak. Indeed, in a large-scale testing of TOU rates in California, there were significant categories of participants whose total energy consumption did not change at all, but because they shifted use from high-cost periods to low-cost periods, the DR program resulted in significant savings from changes in the time pattern of consumption.[3]

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The second main benefit from DR is when it reduces peak demand. When peak demand is reduced, then the need for new power plants to serve peak times is reduced. Because many power plants that serve peak demand have very low utilization factors, on the order of only 100 hours out of the year (or 1 or 2 percent of the total hours in the year), avoiding the cost of building a new peaking capacity can result in significant savings. It is important to note, however, that simply reducing on-peak demand is not sufficient to obtain the benefits of avoiding the costs of building new peak capacity. If new peak capacity is not needed, then there is no avoided cost of new peak capacity. Rather than new peak capacity never being needed, sometimes the situation is that it is not needed for several more years. In this case, the value of reduced peak demand provided by DR must be discounted by the number of years until that value is actually realized. Unfortunately, some have suggested that DR programs be immediately credited with the value of avoided peak capacity when no such capacity is needed. This is akin to compensating a utility for building a generator well before it is needed.[4]

The reliability benefits from DR are really a function of the reduction in peak demand. Because generating units suffer mechanical breakdowns, electric power systems must have a ''reserve margin,'' that is, more capacity than that needed on peak in order to accommodate unit outages. Typically, electric power systems might carry around a 12 to 15 percent reserve margin to ensure reliability. As a result,

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every megawatt of peak consumption reduced by DR results in the savings of not just 1 MW of avoided peak capacity costs, but also the avoided reserve margin. So, if the target reserve margin is 15 percent, 1 MW of avoided peak consumption results in 1.15 MW of avoided peak capacity investment. But only if such capacity is needed. And only – and this is often missed – if the DR program can reliably provide the peak consumption reduction.[5]

DR, however, does not generally provide a special reliability benefit that could not be provided by building new electric power facilities (generation, transmission, and/or distribution). Everything else being equal, a megawatt of generation is equivalent to a megawatt of DR. While there are some exceptions to this, the benefits can be hard to quantify. For instance, the California Energy Commission is encouraging fuel diversity as a goal in order to avoid overdependence on any one particular fuel source in order to prevent the problems like those caused by the high natural gas prices in 2000 and 2001. Stipulating that this is a reasonable goal, DR might have some value in reducing dependence on a particular fuel source by lessening demand for that fuel. The benefit likely to be found in this case is not so much in the expected costs, but in the variance of costs. To the degree that policymakers are risk-averse, this may encourage weighting such benefits more heavily.

Another potential benefit from DR is in increasing the elasticity of demand for electric power.[6] Clearly, sending better price signals to consumers through dynamic pricing programs such as those tested in the California experiment can increase demand elasticity.[7] To the degree that demand elasticity is increased, there is the benefit of decreasing the degree to which market power can be exercised if that is a concern. While this is potentially a significant benefit, there are a couple of factors that are important to note in measuring costs and benefits. First, estimated future costs due to the exercise of market power are, at best, difficult to quantify. Second, DR and the resulting increase in demand elasticity are not the only policy solutions to alleviating the effects of market power. Less radically, new generation that is owned by smaller market participants can have similar effects. Distributed generation is one example of an alternative. The point here is not that DR does not offer benefits in this area, but that it must be fairly weighed against other approaches in determining its value.

Clearly, sending better price signals to consumers through dynamic pricing programs such as those tested in California can increase demand elasticity.

That said, DR programs do have some characteristics that differ from alternatives such as more generation and that should be taken into account. A significant challenge for both operating and planning electric systems is the long lead times necessary for adding capacity in the face of uncertainty about demand growth. Operational flexibility and rapid construction times enable timely adjustments in response to higher or lower demand growth than anticipated. Some DR programs have attractive properties compared to traditional capacity that make them more flexible. For example, direct load control enables a more graduated response by system operators to an impending loss-of-load event by directly turning off customer equipment rather than resorting to brownouts. Other DR resources can be implemented far more quickly than new power plants can be sited and built. For example, CPP tariffs can have an immediate effect on demand by changing the customer's hourly load shape. While a new combustion turbine built to serve peak demand might take four or five years to site and build, a CPP tariff can be implemented in a few months provided that the appropriate infrastructure for advanced metering (AMI) is in place.

This raises the issue of option value. To understand this concept, suppose that there is

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ample capacity in today's power market even at peak times. Prima facie, that would suggest a minimal role for DR in the resource mix since the perceived value for DR would be low. However, as the economy grows, this ''excess capacity'' may be whittled away. In five years' time, a shortage of capacity may appear unless new capacity is built, and there is no certainty whether such capacity would indeed be built. Clearly, if this capacity were not built, during the fifth year DR would have very high value. But it will not be available, since it has its own lead time, most of which is associated with the installation of AMI and some of it associated with implementing rate changes. If decision-makers use myopic decision rules, DR will not be in place in the fifth year and outages will take place. If decision-makers factor in future uncertainties, they will use a process that considers option values. Such a process could suggest that investments in DR resources should be made in advance of their need in order to prevent future outages. That is, it would be sensible to pay an insurance premium for DR today as a hedge against future outages.

Finally, in the foregoing, an aspect that has not been mentioned is that consumption has value. If it did not, then the best DR program would be to simply shut the grid down! Most evaluation approaches to DR, and electric power systems, in general, assume that demand is fixed. As a result, the approach is to minimize system costs of meeting fixed demand at a given level of reliability. DR programs that decrease demand at costs that exceed the willingness of consumers to pay for supply won't be cost-effective and should not be pursued. DR does not need heroic assumptions to justify it, but its value should be determined on an equal basis with competing solutions.

Energy efficiency programs often pass the total resource cost test but fail the ratepayer impact measure test.

III. Toward a New Paradigm

The SPM, originally developed in California to standardize the evaluation of utility energy efficiency programs, is now being used nationwide to perform such evaluations. Lately, it has also been used to evaluate DR programs. However, there are several limitations with the SPM. A key assumption underlying the SPM is that customer demand for energy services is a given, i.e., that it is perfectly price-inelastic. Thus, if a customer replaces an old air conditioner with a more efficient one that uses 20 percent less electricity, the SPM assumes that electricity usage for air conditioning would fall by 20 percent. In reality, since the new air conditioner would reduce the cost of cooling a building, consumers might increase the amount of air conditioning they use, thus eroding some of the potential drop in electricity consumption while, at the same time, increasing their consumer surplus.

Our experience has shown that energy efficiency programs often pass the total resource cost (TRC) test but fail the ratepayer impact measure (RIM) test.[8] In such cases, if the TRC test were adjusted for price elasticity effects caused by the need to raise rates, it would provide smaller benefits than the SPM-TRC test. In addition, the SPM penalizes programs that create customer value by increasing electricity use, reducing environmental emissions, or raising productivity. Such programs, conversely, fail the TRC test and the Participant test, but pass the RIM test.

These and other weaknesses of the SPM are compounded when it is implemented in practice because various stakeholders are often reluctant to incorporate externalities and intangible factors in the assessment, even though there are some provisions within the societal version of the TRC test for including such effects. Typically, it is the lack of agreement on what values to use for these factors that limits their use in the SPM rather than any conceptual limitation in the SPM.

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The primary limitation of the SPM is that the ''societal value function'' is simply set equal to reductions in supply-side costs, as measured by avoided costs. To the extent that other factors are ignored, suboptimal policy decisions are likely to follow. There is a need for a new framework that would maximize economic welfare, subject to resource cost and technological constraints, and not simply minimize total resource costs at a fixed level of service.

SPM has several other limitations:

- It ignores uncertainties in the magnitude of customer response to new rates, the number of participating customers, the value of avoided cost and program implementation costs.
- It doesn't recognize that electricity service levels are likely to be changed by DR programs. SPM relies on changes in consumer bills to measure changes in consumer welfare.
- It penalizes customer actions that increase electricity usage, even though customers might derive positive economic value from those actions. And it gives positive value to customer actions that decrease usage, as long as the costs of the actions are less than the benefits, even if such actions significantly reduce consumer welfare. For example, at relatively low cost, customers can turn off all their lights. This would lower their bills, reduce total resource costs and pass the TRC test. However, the costs associated with lost productivity and safety risks would not be factored into any of the SPM tests, leading to a bad decision.
- It does not factor in customer outage costs. An EPRI study estimated that the cost of outages to the U.S. economy is in excess of a $100 billion, suggesting that the figure for California could be at least $10 billion.
- It ignores distributional effects that involve transfer payments between customers or that arise when a new policy makes some customers better off and other customers worse off.
- It ignores qualitative and intangible factors such as the value of improved customer bills, Web site informational displays, and enhanced power quality.

It may not make sense to develop a new approach from scratch, since SPM is widely accepted and understood by utilities and regulators.

Several options are available for addressing the limitations of the SPM. It may not make sense to develop a new approach from scratch, since SPM is widely accepted and understood by utilities and regulators. Any brand new approach could be dismissed as being an untested black box. Thus, we set forth some incremental recommendations that make enhancements to the SPM.

First, incorporate consumer and producer surplus into the analysis. For example, the SPM relies on the Participant test to measure impacts on customer well-being, which is based entirely on changes in customer bills assuming unchanged service levels. A new framework would recognize that demand curves are downward sloping and would estimate changes in consumer surplus caused by resource DR programs. See the Sidebar for additional discussion of this point.

Second, incorporate uncertainty into the analysis in order to capture the option value of DR. This would allow the analyst to determine the sensitivity of the go/no go decision to key assumptions. Priorities for new information collection would be identified. This approach is well suited to factoring decision-maker risk preferences into the analysis, since it would yield the probability that a program is cost-effective.

Third, incorporate outage costs. One approach to this was developed in the early 1980s and incorporated into EPRI's Over-Under Capacity Planning model. In this model, the value function expresses the price of electricity as a function of capacity levels. When capacity levels are low, outage costs are likely to be high and the price of electricity (including the cost of undelivered electricity) will be high. When capacity levels are very high, there will be unutilized capacity and this will also contribute to

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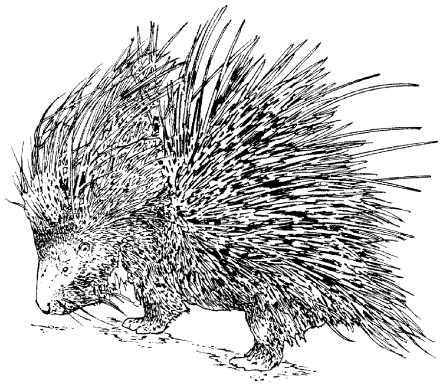
high prices. Inputs into the analysis include the economic costs of various levels of outages by sector, which can be extracted from the literature. Such a framework would allow direct computation of the dynamic response of the loss of load probability (LOLP) to different DR resources and values can be placed on multiple attributes of each scenario. In the original over/under framework, that was limited to describing blocks of capacity-like response to outages with a value placed on each. The final outage-block was the cost of outage to customers, weighted by the LOLP. As noted above, however, outage cost savings by DR must be compared to investments in competing programs.

Fourth, incorporate distributional effects, such as the ''feedback'' effect of DR on wholesale prices. The resulting decrease in electricity bills is a benefit to consumers and a loss to producers. Since this is a transfer payment, the TRC test disregards it. However, it can be very important for policymaking. One way to include it in the society value function is through the multi-attribute utility decision making approach. Another key distributional issue that needs to be evaluated is how to handle situations in which a new policy improves aggregate social welfare but creates winners and losers. Quite often, regulators will only implement policies that make at least one person better off and no one worse off (i.e., only implement Pareto Optimal policies). But this approach may be inferior to other concepts of optimality, such as Kaldor-Hicks Optimality. This definition of optimality says that, if the gainers from a public policy can compensate the losers, that policy is worth doing even if the gainers do not make the payments. Of course, if the winners do make the payments, the outcome satisfies the more restrictive definition of Pareto Optimality.



Fifth, incorporate qualitative factors, which could be either positive or negative. One approach to incorporating qualitative factors is through multi-attribute utility analysis. This can be implemented through survey techniques, which are used to elicit ranges and values for the qualitative factors and to create weights in the societal value function. It would be advisable to explore other methods for dealing with qualitative factors.

IV. Conclusions

This article has shown that there is value in DR but it needs to be evaluated correctly. DR creates value when it encourages electric consumers to reduce load at peak times by either curtailing energy using activities or shifting them to off-peak times. Load that is reduced during times when the power system has encountered critical conditions (in the form of higher prices on wholesale markets or stress caused by supply insufficiency) will carry greater value than load that is reduced during normal times. Effective DR programs will be able to draw large numbers of participants and create higher value than programs that draw fewer participants.

The pricing experiment in California has shown that well-designed dynamic pricing programs can have a significant impact on critical peak loads, even for residential and small commercial and industrial customers. California's three investor-owned utilities are using the experimental results to develop business cases for AMI.

A key question in developing these business cases is how much value to attach to a kW of load that is curtailed during critical times. This, of course, depends on what it would have cost to supply that kW. Different methods are available for making such valuations, including California's SPM, but they are not without their limitations. Recognizing these limitations, the California Public Utilities Commission is initiating a new proceeding on the topic of valuing DR investments.[9] The discussion in this article about improving the SPM will hopefully

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provide input into such deliberations.

Sidebar: The Simple Analytics of Demand Response

Under current regulatory practice, cost-effectiveness analyses of DR programs is based on the SPM family of tests. A primary limitation of the SPM family of tests is that it does not account for the loss in consumer welfare that occurs when consumers reduce peak period usage nor the gain in consumer welfare that occurs from increased off-peak usage. It would be too much of a coincidence if these two effects simply canceled each other out. Thus, we can expect the participant test used in the SPM to have a bias. To assess the magnitude of this bias, it is useful to introduce the concept of consumer surplus. This is the difference between the value consumers derive from consumption and the amount they spend on that consumption.

The value consumers derive from consumption, or the consumer's willingness to pay, equals the sum of the marginal utilities of the various units consumed. For a normal good, the marginal utility declines with additional units consumed, and is reflected in the familiar downward sloping shape of the demand curve.

Graphically, CS consists of the triangular area toward the left of the downward sloping demand curve and above the horizontal price line. This is shown in

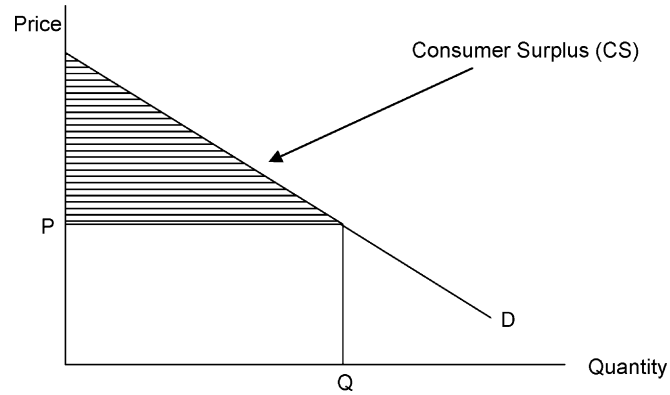

Figure 1: Consumer Surplus Responds in Intuitive Ways to Price Changes

Figure 1.[10] CS responds in intuitively expected ways to price changes. If the price of a commodity goes up, CS shrinks and if the price goes down, it expands.[11]

As noted earlier, there is no reference to CS in SPM, which relies instead on changes in the consumer's bill to measure changes in consumer welfare. The writers of SPM were not confident that regulators and other policymakers would put much faith in estimated price elasticities, which are a critical element of estimating CS. They were concerned that controversies about the price elasticities would enter the discussion, and prevent any consensus from developing about the program's cost-effectiveness. Thus, they choose to focus only on bill changes. It is important to keep in mind that the bulk of the applications of SPM were expected to involve technology programs, and not rate programs. The price of electricity was held constant in such calculations, since the developers of SPM were mostly concerned about energy efficiency programs and technology-based load management programs. Changes in the quantity of electricity consumed were determined exogenously, and were often based on engineering rules of thumb. It was common to reduce electric usage in proportion to the efficiency change represented by a movement from the old technology to the new technology.

When SPM is applied to rate programs, such as a time-of-use (TOU) rate, it is no longer possible to stay away from price elasticities. These are necessary for predicting the new quantities that would result from the new prices. Since the old and new prices are known, along with old quantities, price elasticities can be used to predict new quantities. Thus, old and new bills can be estimated, and bill changes derived by subtracting the new bill from the old. This is what we have done in our analysis thus far.

However, we have the information that is needed to calculate CS. TOU rates raise prices during the peak period and lower them during the off-peak period. Higher prices during the peak period result in lowered consumption, and ''consumer sacrifice''; lower prices during the off-peak period raise consumption,

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Table 1: Bill Savings and Consumer Surplus (Dollars per Month)

Peak Share of Monthly Use (%)	Variable	Price Elasticity of Demand −0.1	−0.2	−0.5	−1.0
10	Bill savings	7.2	14.4	36	72
	Consumer surplus	3.6	7.2	18	36
30	Bill savings	1.05	2.1	5.25	10.5
	Consumer surplus	0.525	1.05	2.625	5.25
50	Bill savings	0.8	1.60	4.0	8.0
	Consumer surplus	0.4	0.8	2.0	4.0

and ''consumer gain.'' It is an empirical question whether the gain is greater than the sacrifice.

Is there a strong relationship between bill savings and consumer surplus for revenue-neutral rates? Yes, for two-period TOU rates that are revenue-neutral, bill savings are *twice* as large as consumer surplus. This can be seen by considering the following example. The customer is assumed to consume 1,000 kWh per month and face a flat rate of 5 cents/kWh. She later moves to a revenue-neutral TOU rate with a peak price of 7 cents/kWh and an off-peak price of 3 cents per kWh. Her original monthly bill is $50 and her new bill, with unchanged usage values, is also $50. Thus, the TOU rate is revenue-neutral. The results are summarized in **Table 1** under a variety of assumptions about the share of peak usage in monthly usage and about the price elasticity of demand in the peak and off-peak periods.[12] In all case, changes in CS are positive, indicating that welfare is improved by shifting to TOU rates, i.e., consumers gain more by increasing off-peak usage than they lose by reducing on peak usage. However, the estimated value of CS is exactly *half* the value of bill savings. This general result holds for a wide variety of cases with linear demand, revenue-neutral TOU rates, equal peak and off-peak elasticities, and zero cross-price elasticities. For simplicity, we had assumed the incremental cost of TOU metering to be zero. Both bill savings and consumer surplus would decline by the same amount if these costs would be introduced in the calculation.

The SPM tests also include the TRC and RIM tests defined further below. The economic welfare tests include the producer surplus test and the economic surplus test.

Producers surplus (PS) is the difference between the total revenue from producing a certain amount of electricity and the cost incurred in producing those units. Graphically, it constitutes the triangular area below the price line and to the left of the marginal cost curve. This is shown in **Figure 2**.

Economic surplus is the sum of CS and PS. In a competitive market, price equals marginal costs, and at that point ES is maximized, as shown in **Figure 3**. The value that customers place on the utility derived from consuming the last unit is exactly equal to the marginal cost of producing that unit. Economic efficiency is maximized. Any other price would reduce welfare, and this constitutes one of the central theorems of welfare economics. Thus, from the perspective of welfare economics, the objective should be to maximize ES, which won't often yield the same policy conclusions as maximizing either the TRC or RIM tests.

In the real world, and especially in the world of electricity, prices are rarely based on

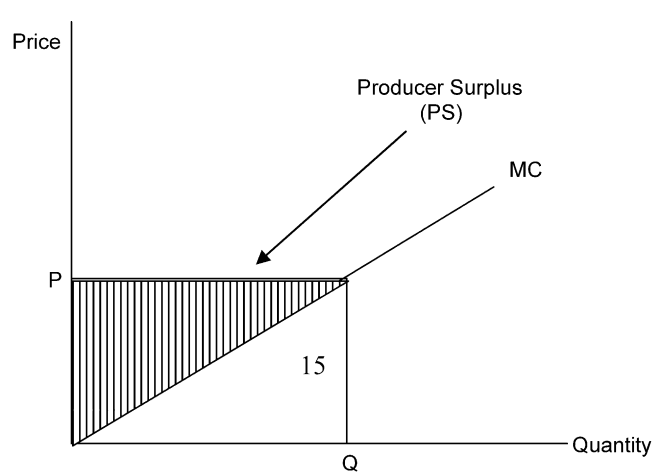

Figure 2: Graphical Depiction of Producer Surplus

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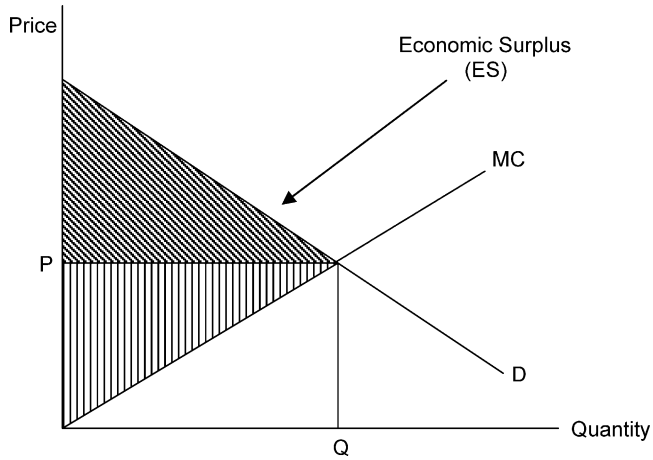

Figure 3: Economic Surplus is Maximized when Price Equals Marginal Cost

marginal costs. Under cost-of-service regulation of electric monopolies, prices are often set equal to average costs. Thus, they exceed marginal costs during the off-peak period and are below marginal costs during the on-peak period. There is a potential for improving economic efficiency by raising prices during the on-peak period and lowering them during the off-peak period, so that they better approximate the marginal costs of electricity. The new prices need to reflect both marginal energy and marginal capacity costs.

A shift to TOU pricing would improve economic efficiency in the aggregate, i.e., for all customers, if it raises ES. However, even if ES rises in the aggregate, some customers may be made worse off. This should not prevent that policy from being implemented, according to the Kaldor-Hicks criterion in welfare economics.[13] These authors argue that if the gainers from a public policy can compensate the losers, that policy is worth doing. The Kaldor-Hicks criterion allows a wider variety of policies to be considered than the more restrictive Pareto criterion, which would only allow such policies to be undertaken that made no one worse off, and made at least one person better off.

A simple example of the relationship between the SPM tests and economic surplus is provided below. This example continues the discussion of the previous consumer who uses 1,000 kWh per month. She is assumed to use half of that in the peak period and the other half in the off-peak period. The flat rate and TOU rates are as discussed earlier and the price elasticity of demand in both periods is −0.50. For simplicity, we have assumed that the marginal cost curve is constant at 5 cents/kWh. This assumption is often made when evaluating demand-side programs since they don't change the demand–supply balance sufficiently to change the value of marginal costs.

Figure 4 displays the results for the peak period and **Figure 5** displays them for the off-peak period. The following definitions are used in measuring the different welfare impacts:

Bill Savings = Old Bill − New Bill = $P \times Q - P' \times Q'$ = Participant Test Benefits = Revenue Loss (which is considered a cost under RIM but disregarded TRC, since it is a transfer payment between participants and non-participants), where the primes denote new values associated with TOU pricing; this formula is applied individually to peak and off-peak periods and the results are added to obtain a monthly value.

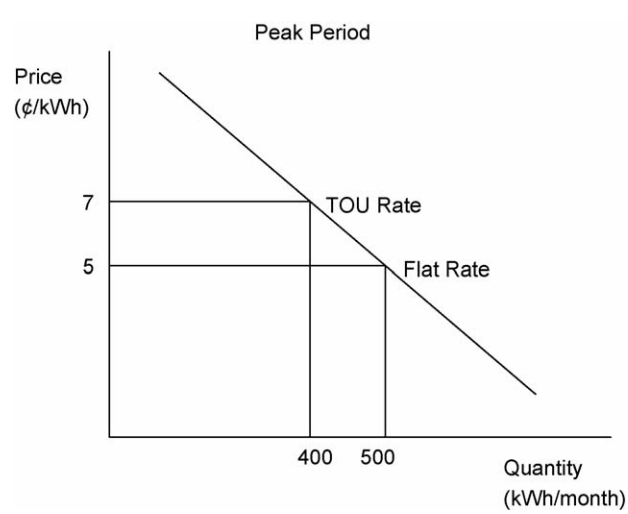

Figure 4: Results for Peak Period

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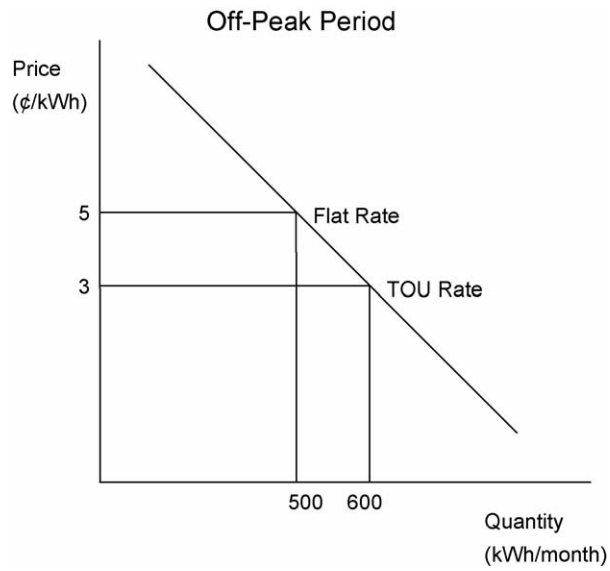

Figure 5: Results for Off-Peak Period

TRC = Total Resource Cost = Delta $Q \times$ MC, and it was similarly computed as the sum of peak and off-peak values.

RIM = Ratepayer Impact Measure = TRC − Bill Savings = Producer Surplus (defined below).

Delta CS = difference between the value that accrues to consumers when they consume a given quantity and the amount they spend in order to consume it. For the peak period, it is the sum of the area of the rectangle bounded by the new and old price at the new quantity and the triangle with height equal to Delta P and base equal to Delta Q.

Delta PS = Difference between revenues that accrue to producers from selling a given quantity and their cost in producing it

$$\text{Delta ES} = \text{Delta CS} + \text{Delta PS}$$

The results are summarized in **Table 2**. The table shows that as prices rise in the peak period, customers experience a negative bill impact of $300. The opposite occurs in the off-peak period, where the bill falls by $700. The total bill for the month falls by $400. This is the customer's bill savings and represents her benefits under the Participant Test of the SPM. Marginal costs fall by $700 in the peak period and rise by $300 during the off-peak period, yielding a net value of $400 in avoided costs. This is the

It won't take much of a change in the underlying assumptions to create a situation where the SPM tests and ES will diverge.

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Table 2: Summary of Results (Dollars per Month)

Row	Variable	Time Period		
		Peak	Off-Peak	Monthly
(1)	Bill savings (participant)	−300	+700	+400
(2)	Avoided costs (TRC)	+700	−300	+400
(3) = (2) − (1)	Impact on rates (RIM)	+1000	−1000	0
(4)	Consumer surplus (CS)	−900	+1100	+200
(5)	Producer surplus (PS)	+1000	−1000	0
(6) = (4) + (5)	Economic surplus (ES)	+100	+100	+200

value of the TRC test since there are no administrative program costs or metering costs in this example. The RIM test is the sum of the TRC values and revenue losses (i.e., negative bill savings) and computes to zero. The change in consumer surplus is $200, which is again half of the amount of bill savings. The change in producer surplus is zero and the economic surplus, being the sum of consumer surplus and producer surplus, works out to $200.

In this example, the TRC test is $400, and suggests that the program should be implemented. The economic surplus test is also positive but half the size of the TRC test. The RIM test is zero. It won't take much of a change in the underlying assumptions to create a situation where the SPM tests and ES will diverge.■

Endnotes:

1. Ahmad Faruqui, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *Getting out of the Dark*, REGULATION, Fall 2001, at 58–62.

2. Governor's Office of Planning and Research, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Sacramento, CA, July 2002. Can be accessed at http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf. The first edition of this manual was issued in 1983, jointly authored by staffs of the California Public Utilities Commission and the California Energy Commission. A revised edition was issued in 1987–1988.

3. Ahmad Faruqui and Stephen S. George, *Quantifying Customer Response to Dynamic Pricing*, ELEC. J., May 2005.

4. Though the discussion here has focused on savings due to the reduction in peak consumption and hence savings from avoided peak capacity, there are situations in which if demand is lowered over a greater number of hours, then there could possibly be savings from avoided cycling or baseload capacity as well. There are also benefits from reduced peak consumption in avoiding the need for new investment in transmission and distribution system assets.

5. Otherwise, the reliability benefit is not there. Indeed, if a demand response program was prone to non-compliance or very variable participation, then there might be negative reliability impacts. That is, a megawatt of expected reduction in peak demand might result in the need for a larger reserve margin in order to provide a given level of reliability if the variance of the reduction is large.

6. The price elasticity of demand of a commodity is a dimensionless number, being the ratio of the percentage decrease in demand to the percentage increase in price, other things being held constant.

7. Of course, sending better price signals, in and of itself, is valuable in that it increases allocative efficiency.

8. The TRC test measures the impact of a demand-side program on total resource costs, including the cost of generation and demand-side management. It does not factor in any revenue losses arising from changes in customer loads. The RIM test measures the impact on average rates and factors in revenue losses and cash payments from utilities to customers.

9. *Administrative Law Judge's Ruling on Scope and Schedule for the 2006 Update to Avoided Costs and E3 Calculator Directed by Decision 05-09-043*, Rulemaking R.04-04-025, California Public Utilities Commission, Dec. 27, 2005.

10. CS has been around a long time, ever since French engineer Jules Dupuit introduced it in 1844 while estimating the value of public work projects. The English economist Alfred Marshall popularized the concept in the early part of the twentieth century and it is now found in most introductory texts on economics.

11. Some authors, beginning with Sir John Hicks of Oxford University in the 1940s, have criticized CS for being a misleading measure of changes in consumer welfare. It involves movements along a demand curve where income and not consumer welfare is being held constant. These authors have argued that a better measure is obtained by holding the consumer's utility constant, and asking what income compensation needs to be paid to the consumer at the higher price so that he or she can experience the same level of satisfaction that he or she was experiencing at the old prices. However, for small price changes and low values of price elasticity, CS is a good approximation to the theoretically more accurate welfare measures.

12. These ranges are reflective of percentages of use when the peak TOU period is defined as four to six hours during week days.

13. See, for example, the discussion in Ch. 16 of WILLIAM J. BAUMOL, ECONOMIC THEORY AND OPERATIONS ANALYSIS, 2nd ed. (Englewood Cliffs, NJ: Prentice Hall, 1965).

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