MID-ATLANTIC DISTRIBUTED RESOURCES INITIATIVE

ACTION ITEMS: PRICING TO INDUCE CUSTOMER DEMAND RESPONSE

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Decades of experience and, recently, pilot programs in several states that have tested innovative rate structures demonstrate that there is a significant amount of demand response that time- and location-sensitive retail prices can inspire. MADRI therefore urges policymakers to evaluate and adopt pricing structures (and their associated metering technologies) and other policies that will most cost-effectively capture that demand response, and do so in ways that are consistent with other stated objectives, such as consumer protection, economic efficiency, equity, and environmental protection.[1]

MADRI has identified actions that state regulators should consider in order to more closely relate retail prices (of default service, which effectively remains a monopoly) to the underlying, market costs of power, and in this way to induce economic demand response. After some consideration of alternative rate structures that could increase the amount of demand response among default service customers (see Appendix 1), the MADRI Regulatory and Business Subgroups have concluded that critical peak pricing offers particular promise of achieving this goal.

Critical Peak Pricing. CPP is a retail electricity pricing structure under which customers are charged a high price during a limited number of critical peak periods initiated in response to electricity market or system conditions such as wholesale price spikes or supply shortages. Depending on the particular tariff, the critical peak price may either be fixed at a pre-determined level or varied to reflect short-term market or system conditions. Critical peak pricing may be combined with either a time-of-use rate or a flat rate. (See Appendix 2 for illustrations of different types of CPP.) Gulf Power in Florida has been testing a CPP program for several years, California just completed a two-year pilot, and Public Service Electric & Gas in New Jersey will implement one this year.[2]

An integral component of CPP, and upon which its efficacy in evoking significant and persistent demand reductions depends, is a device linked to the advanced metering infrastructure (AMI) that enables customers to manage their energy usage by pre-programming the operation of particular end-uses or circuits (e.g., cooling and heating systems, water heating, and pool pumps) according to the prices that the customer is willing to pay for those services. Beyond programming, the customer's direct involvement is unneeded; response is automatic (but can be overridden manually, if the customer so chooses). Discretion belongs entirely to the customer: not only can he or she

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[1] Price-induced demand response is not intended to substitute for other means of achieving cost-effective reductions in demand, such as energy efficiency and ISO/RTO-managed demand response programs. Retail rate structures that send customers efficient price signals are simply one in a set of complementary strategies intended to improve the overall efficiency of the electric sector.

[2] An interesting feature of the PSE&G pilot will be its use of wholesale day-ahead hourly prices for the retail critical peak prices. As a consequence, both the occurrence of a critical peak event and the price associated with it will be variable. The Gulf Power program, in contrast, sets the critical peak price in the tariff (e.g., $0.29/kWh); only the incidence of the critical peak events is unknown.

program usage in response to critical peaks, but also in response to the predefined time-of-use prices (periods) as well.

The California pilot compared the effects of inverted block rates (currently in effect) with TOU and critical peak prices. It involved some 2,500 residential and commercial customers dispersed throughout the service territories of the state's three large investor-owned utilities. Its results are statistically significant. A central finding of the effort is that customers of all types and usage levels were able to reduce and shift demand in response to critical peak prices, and that their responses produced greater reductions and bill savings than responses to inverted block and TOU prices yielded.[3] Between 70 and 80 percent of the customers on CPP rates were able to change their usage, and by doing so were able to reduce their bills by anywhere from five to twelve percent. They reduced their peak loads by 30 percent during critical peak days. Customer acceptance of the CPP rate design was very high: 80 percent of participants favored the rates, finding them easier to understand than the state's five-tiered inverted block rates. Of particular value to customers was the capability to automate (pre-program) their responses to high prices. And, lastly, investment in higher efficiency appliances and other end-uses increased among customers under the CPP tariffs.[4]

Appendix 3 provides an illustrative CPP tariff, based in large measure on PSE&G's Residential Service Pilot (Rate Schedule RSP) and which differs in certain material respects from the examples in Appendix 2. It overlays a limited fixed-price CPP on a seasonally differentiated, TOU rate structure and does not necessarily rely on an advanced metering infrastructure with customer-automated demand response. It is "limited" in that critical periods can only occur during the on-peak TOU periods.

Possible Actions. The implementation of critical peak pricing (and other dynamic rate structures) requires regulatory leadership and action. Regulators can evaluate their efficacy through rate design workshops and dockets, and can direct staff, default service providers, and other interested stakeholders to develop recommendations and proposals (jointly if possible). In certain instances, pilots may be appropriate (designed to take advantage of existing metering and communications infrastructure), but, as information about dynamic pricing proliferates, the need for pilots diminishes. Indeed, it may be possible to approach the question though a multi-state process (particularly where there are multi-state distribution utilities), thus leveraging available resources and avoiding duplication of effort. Customer acceptance is critical to the success of a program, of course, and thus whatever approach is ultimately chosen—pilots or direct adoption—must be accompanied by a comprehensive educational campaign.[5]

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[3] It was also true in California, as with Gulf Power's program in Florida, that the CPP-induced demand response resource (MW reductions) was greater than that acquired through utility direct load-control programs.

[4] Levy, Roger, *Retail Pricing Options for Small Customers: the California Statewide Pricing Pilot,* presentation to the New England Restructuring Roundtable, 28 October 2005.

[5] Appendix 4 touches on some additional, but also important, policy questions that policymakers will need to grapple with when designing dynamic price structures.

Appendix 1: The Range of Pricing Structures

The MADRI Pricing Subgroup looked at the pricing continuum, ranging from flat time-insensitive charges to real-time market-based prices. The Subgroup did not analyze the cost-effectiveness of the various rate designs and the metering infrastructures needed to support them. An idea of the relationship of metering infrastructure cost, on the one hand, to demand response savings yielded by a particular rate design, on the other, is implicit in the matrix below, but it may not be accurate: as metering and communications costs decrease, the economics of the more time-sensitive price structures improve, which is to say that the small levels of demand response associated with lower-volume customers begin to justify the investments that enable them. Rate designs that, because of the infrastructure costs associated with them, were once only warranted for high-volume users may now produce significant benefits for the system when applied to the lower-use customer classes.

Matrix of Rate Design Options By Customer Class

	Typical Current Rate Design	Inverted Rate	TOU Rate (Fixed time periods)	TOU plus Critical Peak Pricing	Baseline-Referenced RTP	Market Indexed RTP
Residential	Flat Energy Charge	Default (if kwh-only metering in place)	Default (if TOU meters in place)	*Optional*	*Not Available*	*Not Available*
Small Commercial 0 - 20 kw demand	Flat Energy Charge	*Not Available*	Default (if TOU meters in place)	*Optional*	*Not Available*	*Not Available*
Medium General Service 20 - 250 kw	Demand Charge --- Flat Energy Charge	*Not Available*	Default (until interval metering installed)	Default (after interval metering installed)	*Not Available*	*Not Available*
Large General Service 250 - 2,000 kw	Demand Charge --- Flat Energy Charge	*Not Available*	*Not Available*	Default	*Optional*	*Optional*
Extra Large General Service >2000 kw	Demand Charge --- Flat Energy Charge	*Not Available*	*Not Available*	*Not Available*	Customer Must Choose Between These Two Options	

Appendix 2: Examples of Critical Peak Pricing

There are several approaches to critical peak pricing, and then variations upon them. Mainly they go to the question of the underlying rate design and the pricing for the critical peak period. One option is non-TOU pricing with a fixed critical peak price. It would give customers a flat rate during all hours, except for the critical peak period, and a fixed rate during the critical peak hours that is some number of times (perhaps three to five) greater than the "normal" rate. The advantage of this is that it allows customers to focus their efforts exclusively on the critical peak periods, when demand-response is most valuable. The disadvantage is that it "loses" some of the off-peak load-shifting incentive that TOU rates create.

Another approach is TOU pricing with fixed critical peak price, which would provide customers with a fixed TOU rates, and a fixed critical peak period price, set at a level that is three to five times the "normal" on-peak price. The advantage of this is that customers know what the price of electricity will be well in advance and can plan a response so that when a critical peak is called, they can implement a planned response. The disadvantage (and this true of the first option as well) is that the fixed price may be above or below the market price at the time it is invoked.

A third option is TOU pricing with a real-time critical peak price, which would provide customers with TOU rates that would be fixed except during critical peak periods. (A real-time CP price could also be used with an underlying flat-rate price structure.) The benefit of this is that it provides the greatest certainty of cost recovery during the critical peak hours for the power supplier, leading to expected lower bid prices for all other hours. The disadvantage is that customers have more difficulty planning their responses in advance, insofar as they do not know what the critical peak price will be. (They can, however, program certain end-uses to cease drawing power when the price exceeds a specified threshold. This requires additional micro-processing functionality on premises.)

The following table illustrates these several critical peak pricing alternatives.

Element	***Ex. 1: Flat Rate With Defined CPP***	***Ex. 2: TOU Rate with Defined CPP***	***Ex. 3: TOU Rate with Market CPP***
Sum of Delivery and Power Supply Rate Elements ($/kWh)	All kWh @ $.09 except CP kWh @ $.60	7 A.M. to 7 P.M. @ $.117 7 P.M. to 7 A.M. @ $.05 except CP kWh @ $.60	7 A.M. to 7 P.M. @ $.117 7 P.M. to 7 A.M. @ $.05 except CP kWh @ Market + margin (~2 mills/kWh)
Maximum Number of CP Hours	40 - 100 per year 10 – 25 per month June – Sept. Only	40 – 100 per year 10 – 25 per month June – Sept. Only	40 - 100 per year 10 – 25 per month June – Sept. Only
Trigger Event for Critical Peak Price	ISO Calls on Day-Ahead Demand Response Resources	ISO Calls on Day-Ahead Demand Response Resources	ISO Calls on Day-Ahead Demand Response Resources
Advance Notice of CP Hours	Day Ahead (24 hours)	Day Ahead (24 hours)	Day Ahead (24 hours)

Appendix 3

ILLUSTRATIVE CRITICAL PEAK PRICING TARIFF[6]

Fixed Price CPP; Constrained Time-of-Day CP Incidence

AVAILABILITY

For use by customers taking service under Default Service Tariffs other than the Real-Time Pricing Tariff and who are not taking service under any load response or curtailable load riders (including any direct load control programs, e.g., A/C Cycling). The Customer may commence service under this rider only as of service rendered beginning the date its meter is read and shall remain on this rider for a minimum of 12 monthly billing periods.

DELIVERY CHARGES

Service Charge: $2.27 per month

Distribution Charges per Kilowatt-hour:

In each of the months of May through October 3.6234¢

In each of the months of June through September 3.0090¢

Other Charges as Required by Law:

[System Benefits Charges, Transition Charges, etc.]

ELECTRIC SUPPLY CHARGES

While participating in this pilot program, the customer is precluded from using on-site generation equipment except when the on-site generation facility is used exclusively as an emergency source of power during Company electric delivery service interruptions.

Electric Supply Charges are as follows:

Summer Months: June through September	**Periods**	**Charges per kilowatt-hour**
Base Price	All hours	5.6933¢
Night Discount	10 PM to 9 AM Daily	(2.8302) ¢
On-Peak Adder	1 PM to 6 PM Weekdays	8.4906¢
Critical Peak Adder	1 PM to 6 PM when called replaces On-Peak Adder	79.2453¢

[6] Based largely on the PSE&G Rate Schedule RSP (Residential Service Pilot).

Non-Summer Months: October through May	**Periods**	**Charges per kilowatt-hour**
Base Price	All hours	6.4303¢
Night Discount	10 PM to 6 AM Weekdays	(2.8302) ¢
On-Peak Adder	5 PM to 9 PM Weekdays, November through March	2.8302¢
Critical Peak Adder	5 PM to 9 PM when called replaces On-Peak Adder, November through March 1 PM to 6 PM when called October, April, and May	17.9245¢

The Critical Periods shall be invoked at the sole discretion of the Company. Critical Periods may be activated for any of the following reasons:

- The PJM day-ahead locational marginal price or the expected bilateral contract energy price exceeds 10¢/kWh;
- The occurrence of company-designated discretionary events, including but not limited to test purposes, program evaluation, etc.; or
- The occurrence of unexpected, generation plant outages, unusual transmission or substation loading, unexpected wholesale energy price increases, or other system emergency conditions.

The Company may invoke a maximum of eight (8) Critical Periods per year. A Critical Period may be only be called in the designated periods. Each customer will be notified by 6:00 P.M. the evening before a day with a Critical Period. Notification will be provided by either e-mail or telephone as elected by the customer at the time of their enrollment in the pilot program and, where installed, through direct communication with advanced metering and associated equipment configured to support this tariff.

The above Energy Supply Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must-Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

TERMS OF PAYMENT:
Bills are due on presentation.

<u>TERM</u> *[If CPP is voluntary or provided under a pilot program]*
Customer may discontinue delivery service upon notice. The Company may terminate the availability of this Rate Schedule at its discretion and upon proper notice to the customer.

SPECIAL PROVISIONS *[(a) and (b) apply if CPP is voluntary or provided under a pilot program]*

(a) Installation and Removal: Metering and Energy Management Equipment will be owned, installed and maintained by the Company at the customer's residence upon customer's initial acceptance of service under the tariff at no charge to the customer. The customer shall provide a suitable location approved by the Company for such facilities. Energy Management Equipment may be removed by the Company [at the conclusion of the pilot or at] any time that the customer decides to withdraw [from the pilot/from the tariff]. Customers completing the pilot may keep the pilot thermostat at no cost.

(b) Voluntary Withdrawal: Customers who voluntarily withdraw from this [pilot program/tariff] can return to the otherwise applicable rate schedule. If customer notification is received at least three days prior to the end of the customer's billing month the customer will be billed for the full billing month under the otherwise applicable rate schedule (the billing month normally ends with the customer's scheduled meter reading date). Customers voluntarily withdrawing from this [pilot program/tariff] are not eligible to reenter the pilot program.

(c) Resale: Service under this rate schedule is not available for resale.

(d) Budget Plan (Equal Payment Plan): Participation in the Budget Plan (Equal Payment Plan) will be suspended for the time the customer takes service under this tariff.

(e) Billing Information: Upon customer request, historical pilot program billing information will be provided to the customer at no charge.

<u>STANDARD TERMS AND CONDITIONS</u>

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

Appendix 4: Other Regulatory Policy Questions Relevant to Time-Sensitive Pricing

The adoption of critical peak or other time-sensitive pricing for default service customers would have the effect of making demand response a condition of service, and therefore raise a number of questions to be addressed by policymakers, including:

- *Applicability*. To which customer classes should critical peak pricing apply? The results of the California pilot challenge the conventional wisdom that low-volume customers cannot or will not modify their usage in response to price changes. Also affecting this question is the cost of metering and telemetry.
- *Voluntary or mandatory?*
- *Opt in or opt out?* This is the practical difference between a voluntary program and a mandatory one (or, at least, one that comes very close to being mandatory). Experience shows that participation is greatly increased in the latter case. It requires customers to affirmatively withdraw from, rather than enroll in, the program, which means that many more will have actual experience with it. The very high acceptance rates of the California program suggest that an opt-out program will result in high numbers of customers remaining in it.[7]
- *Metering and telemetry*. The costs of communications and metering are coming down, thus improving the cost-effectiveness of the more dynamic rate designs. A commitment to these rate designs necessitates a commitment to the infrastructure in support of them. Policymakers will need to address these issues of metering cost and cost recovery when evaluating the rate designs themselves. One factor affecting cost is the manner of deployment: there can be significant economies of scale associated with ubiquitous installations (which, necessarily, are required for mandatory CPP and other dynamic rate designs). Another factor is the extent to which existing utility metering and communications infrastructure, deployed for other demand response programs, can be adapted for CPP.
- *Impact on competitively acquired default service.* Can the retail rate structure of default service (typically full requirements with defined prices for a specified period) that was obtained by competitive means (auctions, RFPs, etc.) be modified into a disaggregated dynamic daily product? A critical peak pricing regime will affect both the costs of providing default service and the level of revenues collected. As part of their consideration of CPP (and other time-sensitive pricing structures) for default service, regulators will need to evaluate, among other things, whether and how the procurement and terms of default service should be amended to allow such rates to be implemented. To the extent that default service is provided under contracts of specified duration, it is

[7] Another concern about voluntary programs is not apposite here. Rate designs that are optional typically lose a significant degree of their potential effectiveness, as customers who will benefit from the new rate without having to alter their load profiles will migrate to it, while those whose bills will increase under it (absent any response) will generally avoid the new rate. This, however, should not be a problem with critical peak pricing, as it is simply a real-time overlay on existing rates: under CPP customers cannot adjust their usage to a static rate structure, such as TOU, in order to take advantage of its lower cost elements. They merely respond to a price if and when it is presented to them. And if that price is set properly, neither usage or interruptions will create financial harm or windfalls for the provider (although it could have impacts on the recovery of distribution system costs).

probably unlikely that significant changes can be implemented without revisiting the terms and conditions of service. A sensible approach might be simply to call for specified rate designs as a term of service when putting the renewal of power supply for default service out to bid. Typically today, default service is put out to bid in processes managed or overseen by state regulators. Classes and rate designs specified in the RFP and suppliers bid the prices at which they're willing to serve. The introduction of a new rate structure needn't change this approach to procurement. In the case of CPP, programs terms to be set out in the RFP would include historic load shapes and billing determinants, the underlying rate designs, the number and duration of CP events, and the CP price (pre-set or market-based?). Bidders will value the risk (positive or negative?) of price-induced demand response, which will be reflected in bid prices. Presumably, price-induced demand response should benefit providers by yielding better load factors: cutting peaks cuts costs.

- *Who makes the CP call?*
- *Risk.* Do dynamic price structures increase or decrease the financial and business risks faced by default service providers? Is there, for example, a non-symmetry between revenue collections by the provider and payment for the energy supply contracts (caused by an inability to pass costs directly through to customers)? What, if any, measures (e.g., balancing accounts) should be taken to limit such risks? To the extent that there are new risks to be managed, a measured, phased-in implementation of the new rate designs might be warranted, during which the overall benefits and costs can be evaluated and dealt with.
- *Who makes the CP call?* Another issue related to CPP's impact on the structure of default service and also to the risks DSPs face is that of the triggering of a critical peak event? What entity makes the call? If it is the DSP, it implies relationships with the customers that it may not have. If it is another entity—e.g., the system operation—the DSP may now bears a risk (affected in part by whether the CP price is fixed or indexed to the market) that it cannot directly manage.
- *Impact of price volatility on consumers.* While experience suggests that most residential consumers can deal with variable prices, there will nevertheless be some fraction of users that will not be able to adjust their consumption and will therefore see higher electricity bills under the new rates. Policymakers may want to consider ways to mitigate this impact. It may, for example, be appropriate in certain circumstances and for certain customers to introduce alternative price schedules that, for a premium, hedge the volatility risk.
- *Portfolio management.* How can dynamic pricing be integrated into a portfolio planning approach that aims to assure long-term stability and minimize volatility? Until there is meaningful experience with the rate structures, so that regulators and providers gain an understanding of how different populations respond to them, it will be difficult to accurately predict the resource value of the demand response that they provide. This is something of a "chicken and egg" problem, but we don't think it should dissuade policymakers from making greater use of dynamic pricing structures. It will be important, from the outset, that regulators require detailed monitoring and reporting of consumer behavior (e.g., changes in load

profiles and customer migration from default service), which will enable later evaluation of the benefits and costs of the new rates.