

United States of America
Before the
Federal Energy Regulatory Commission

Comments of

Demand Response and Advanced Metering Coalition (DRAM)

In

Docket AD06-2-000
Assessment of Demand Response Resources

In Response to

November 3, 2005 Notice of Proposed Voluntary
Survey and Technical Conference

December 19, 2005

I. Introduction

DRAM is an industry association that includes the leading providers of advanced metering and demand response services and technologies. DRAM members¹ represent a broad spectrum of technologies, applications and products and their businesses focus on the questions that the Commission is looking to assess in implementing its responsibilities under EPACT.

For policy purposes, DRAM is a consensus-based organization where the members have agreed to definitions and positions related to demand response and provide input to policy makers at the State and Federal level on numerous occasions.

II. Responses to Questions

DRAM believes the Commission has put forth a number of important questions that must be addressed to meaningfully complete the Assessment of DR that it is called for in the Energy Policy Act of 2005 (EPACT). That said, DRAM does not have the data to respond to all of the questions. In some cases, as we indicate, DRAM assumes that some questions are directed at utilities, regional system operators or other parties which have the necessary data to respond to such questions.

A. Advanced metering and communication systems

- ***How should the Commission define advanced meters and communication systems for the purpose of reporting to Congress?***

DRAM believes that it has developed appropriate definitions for advanced meters, advanced metering and many other terms that are inherent to demand response and its enabling technologies. Those definitions are attached as Attachment A.

DRAM's definitions for advanced metering and communications systems are not based on a particular type of technology but on the capabilities and functionality of technology that is needed in order to enable demand

¹ Members of the DRAM Coalition participating in this filing include: Landis & Gyr, eMeter, Echelon, E-MON/MeterSmart, DCSI/TWACS, Elster Electricity, SmartSynch, Electric City Corporation, Invensys, Comverge and EnerNOC

response. As such, DRAM believes that its definitions are appropriate for use by FERC in its eventual reporting.

DRAM's definitions could be applied to the responses to the FERC metering survey to determine the penetration and saturation of advanced metering per the EPACT requirement.

- ***Are advanced meters necessary to implement demand response and time-based rate programs? Can sufficient demand response be fostered from non-communicating, non-hourly meters?***

Advanced meters and advanced metering systems are not necessary to implement every type and variation of demand response program. For example, a customer end use can be remotely controlled by a utility or third party in return for the customer receiving some form of payment which may or may not be related to the actual number of controlled events.

What is necessary to implement a demand response program is the ability to encourage and reward customers to reduce and/or shift their peak electricity demand and to verify/relate the reduction/shift in relationship to the incentive. Advanced metering measures usage on an interval basis that allows the usage during those intervals (or in different periods or on different days) to be priced differently.

Advanced metering is necessary to enable time-based rates; customers cannot be billed based on time-differentiated prices unless their usage is measured accordingly. The only exception to this would be a non-communicating meter that had fixed TOU registers. This type of meter could enable a TOU rate, but it would not allow any changes to the intervals without meter retrofit. This type of meter would also not allow any other types of time-differentiated rates (such as envisioned by Section 1252 of EPACT). Moreover, this type of meter would not provide the many non-demand response benefits that advanced metering systems yield, which help increase the cost-effectiveness of a deployment of such metering and the demand response programs they enable.

To fully achieve demand response's potential, including from the mass market segment, advanced metering is necessary.

- ***In general, what are the current saturation and penetration levels of advanced meters?***

Most nation-wide or industry-wide surveys of metering that have been conducted in the past have not properly segregated advanced meters from non-advanced meters. In some cases, the surveys have delineated only between Basic Metering and Automated Meter Reading (AMR), with AMR and Advanced Metering being grouped together in one total number.

DRAM believes, however, that at present there are currently approximately 15 million advanced meters installed and operating around the U.S., according to DRAM's definitions. This is out of a total number of electric meters of approximately 115 million.

The draft FERC survey included in its November 3, 2005 Notice is designed in a way that will allow meters to be grouped in a variety of different ways, based on the different attributes and capabilities that the survey questions address. In addition, it will allow differentiation between those advanced metering systems that are or are not actually being used to provide the functionality and capabilities that enable DR.

- ***Does the implementation of an advanced metering system or use of advanced meters reduce utility costs?***

Yes. An advanced metering system brings with it many benefits to the utility that are outside of the area of demand response. Some are more quantitative than others. These benefits can include:

- a. Outage detection and management
- b. Remote connection and disconnection
- c. Increased accuracy of meter reading
- d. Faster and more accurate settlements for customers of retail marketers.
- e. Reduced meter reading costs for monthly billing
- f. Reduced energy diversion and theft
- g. Improved distribution asset utilization through transformer load management and similar activities.
- h. New and previously unavailable data and information on electricity usage patterns and service preferences.
- i. New and previously unavailability to respond to their customers' desires for choices and options from their customers

- ***What level of penetration is needed to achieve cost savings? For example, can advanced meters be used only for certain customer groups or would all customers need to use advanced meters to make their use cost effective?***

The greatest economy of scale for an advanced metering deployment comes via a mass deployment to all customers of a utility or all customers in a given region. Some of the cost reductions come via larger bulk purchases but the majority comes in the area of installation costs and deployment of the communications system.

The most efficient means of installation is to cover a complete contiguous neighborhood or area so that labor and logistics can be deployed most efficiently and therefore most cost-effectively. In addition to greatly

reducing deployment and operating costs, contiguous installations achieve significant utility operating savings (note that to date, the large majority of costs of the advanced meters installed in the U.S. have been paid for via these operating savings). For example, manual meter reading cannot be eliminated without contiguous installations.

The importance of this factor was displayed by the attempts in some states to introduce competitive metering. Competitive metering has not worked, and very few advanced meters have been installed in places where it has been tried because non-utility third parties found that the cost of doing an ad hoc deployment of meters, whereby a meter is installed in one area of the territory one day and in another area the next, was up to 10 times as expensive as meter installation via a mass deployment to all customers. In addition, these scattered installations did not result in any operating savings that could offset the capital costs.

B. Existing demand response and time-based rate programs

DRAM does not maintain a database of DR programs. While it is our assumption that responses to these questions will be provided by utilities, regional system operators and other program sponsors and providers, DRAM does provide the following responses:

- ***Describe the type of programs being used and the benefits or detriments of each programmatic approach?***

Load response programs are of two primary types. The first encompasses a variety of programs for large commercial and industrial customers and include interruptible rates, curtailable programs, and demand bidding programs. The second type is direct control of residential air conditioners and electric water heaters by utilities, in return for monthly or seasonal incentive payments. The participation in these programs is generally on the order of 3-5 percent of peak load for a utility or ISO.

An estimated 10 million load control devices are in operation around the U.S., with perhaps the largest program at Florida Power & Light, which is able to shed 2,000 MW in an emergency. These demand response programs are dispatched during system emergencies and when peak energy costs are extremely high (economic dispatch).

Price responsive programs are also of two primary types. In many states, the largest commercial and industrial customers are on mandatory time-based rates. In all states, utilities offer voluntary time-of-use rates to residential customers to fulfill a PURPA requirement. Participation tends to be extremely low (less than one percent of the population), because a.) the rates are generally very unattractive with high monthly added meter charges and very long on-peak periods and b.) the customers are not made aware of

the programs by the utilities. In a few selected cases, notably Salt River Project and Arizona Public Service, who – not coincidentally – are rivals in the Phoenix area, residential participation approaches one third of the population.

- ***How have these types of programs changed since the early 1990s?***

Three major changes have occurred. In states with restructuring and ISOs, substantial demand response programs have developed to provide demand response directly to the wholesale market. This includes NEPOOL, NYISO, PJM, and CA ISO.

The second change is the introduction of dynamic pricing, including hourly pricing and Critical Peak Pricing (CPP). For some utilities and for some customer groups (large commercial and industrial customers), such rates are becoming the default rate, with customers having the ability to opt out to competitive retailers (NY and NJ, relative to hourly default rates) or other rates (CA, relative to CPP rates).

A third change has to do with load control programs, where some utilities are outsourcing the marketing, deployment, and operation of the programs to third parties in “Virtual Peaking Capacity” programs. Examples include PacifiCorp (Utah) and San Diego Gas & Electric.

- ***Have demand response and time-based rate programs increased or decreased in recent years?***

Overall, there appears to be a slight increase in program activity because of the visibility of the programs operated by the system operators. There also appears to be a slight increase in time-base pricing resulting from restructuring. State by state, the changes have sometimes been large – both increases and decreases. Also noteworthy, there is greater participation by third parties in program delivery in recent years.

- ***Are demand response programs implemented by electric utilities available to all customers, or are they targeted to specific customer groups or geographic areas, e.g., load pockets or transmission constrained areas?***

Most past and current programs are targeted with respect to customers and appear to fall into one of two types: the large commercial and industrial customer programs, generally with diverse participation options; and residential load control programs, which are monolithic.

In a few cases, such as southwestern Connecticut, the programs are targeted at constrained areas, and there has been much more discussion of such targeting in recent years.

C. Annual resource contribution² of demand response

DRAM does not maintain a database of DR programs. While It is our assumption that responses to these questions will be provided by utilities, regional system operators and other program sponsors and providers, DRAM does provide the following responses:

- ***Describe in general the extent of resource contribution by demand response for the geographic area you serve or represent.***

DRAM believes that demand response typically is capable of providing demand reductions of 3-5 percent of annual peak load for periods of up to 100 hours or so per year.

- ***Identify and describe the best available sources of information on the annual resource contribution made by demand response, by region.***

The most obvious demand response resources are generally the large commercial and industrial customers who have great price elasticity (e.g. large smelting plants, cement plants, rock crushers, etc.). These resources have been efficiently utilized by utilities for decades, with some of them now switching over to ISO-based programs.

Residential customers as a group have the greatest price elasticity of any customer group. Residential customers also make up a disproportionate share of annual system peaks because their air conditioning use fluctuates up and down more intensely than that of commercial customers with changes in outdoor temperature. Residential customers also may have greater discretion than businesses in timing of many uses of electricity.

- ***What problems exist in measuring resource contribution? Should the measurement be on the basis of enrollment or on actual quantities used?***

Some level of advanced metering is required to measure the contribution. This can be done for individual customers or for populations (typically a random sample of direct control air conditioning customers is used to estimate load response). The greater the precision in measurement, the greater the ability to reimburse the participant accurately and the more response participants provide. DRAM contends that customers paid for actual reductions – as opposed to average reductions – nearly always provide greater reductions (just as when people pay for their own lunch, they buy less than they do when they pay an average price for a group lunch).

² For purposes of this notice and proposed survey, resource contribution is defined as potential peak reduction at time of system peak.

Another issue in this area, and a challenging one to date, is the customer's "baseline," as many programs pay customers a credit or rebate for reductions below such a baseline when the demand response program is dispatched. However, good methods have been developed to measure this quantity, i.e. the amount the customer "didn't use." These include taking the average of the three highest non-event days during the ten days preceding the event. Unfortunately, since event days are usually the most extreme days, these methods may understate the actual load reduction provided.

D. Potential for demand response as a quantifiable, reliable resource for regional planning purposes

It is DRAM's assumption that specific responses to these questions will be provided by utilities, regional system operators and other program sponsors and providers. DRAM does, however, provide the following responses:

- ***What percentage of total resource requirements could demand response resources reliably provide?***

Traditional demand response programs are able to meet 3-5 percent of peak demands. Pricing programs have found typical reductions of 10-20 percent for residential customers (some programs have found reductions of close to 50 percent for automated response to price signals) and reductions of 3-10 percent for commercial customers. These results suggest that demand response, including dynamic pricing, could easily and reliably meet 10 percent of peak demand, perhaps even 12-15 percent in a robust, mature, and long-term program.

- ***What is the current role of demand response resources in meeting regional resource adequacy requirements and ancillary services?***

DRAM has no comment at this time, other than to reiterate its understanding that on average approximately 3-5% of peaking capacity is met with demand response resources.

Two key features would enable this and the greater potential for demand response capacity to be as reliable or even more reliable than traditional supply sources such as generation. First, the demand response capacity would need to incorporate real time communications to monitor how the assets perform as events occur. Second, penalties should be levied for non performance.

- ***Explain the risks of relying on demand response for resource adequacy. Do the risks differ depending on the type of demand response?***

Every resource has risks. Generally, these risks are mitigated through appropriate risk management measures. Power plant risk is managed through inspections, maintenance programs, ensuring fuel availability (a major contributor to California's Energy Crisis was the inability of small producers to buy natural gas for their plants), etc.

Risks associated with demand response programs also are reduced or eliminated through a variety of measures:

- 1) periodic test operation to validate responses;
- 2) diversity in participant populations (the larger and more diverse, the more predictable the response);
- 3) continuous tracking, measurement, and reporting of event results;
- 4) making sure the resources are matched to the needs (e.g. an air conditioner control program cannot be relied upon to meet winter peaking problems);
- 5) program consistency and maturity (the longer the program has been in operation without major changes, the more reliable the response), and
- 6) providing an appropriate amount of up-front and ongoing education and informational feedback to customers.

- ***What is the potential impact of demand response on overall energy usage?***

Demand response typically results in only a small reduction in total energy usage. This is because demand interruptions occur for less than 1 percent of the hours each year. Also, part of the load from demand interruptions or time-based pricing is shifted into off-peak periods. The former typically result in annual energy consumption reductions of perhaps 0.3 percent.

However, time-based pricing programs, while showing virtually no total usage effect for large commercial customers, often reduce total residential usage by a few percent (one literature survey found an average reduction of 4 percent). In addition, customer feedback studies – where customers receive more frequent and detailed feedback on energy usage – have found total usage reductions of as much as 20 percent, and averaging 11 percent, again for residential customers.

- ***Can time-based rate programs or interruptible/curtailment rate programs be counted as capacity resources in regional plans?***

Yes. Georgia Power has counted on its real-time pricing program as a capacity resource in internal planning for years. Also, regional system operators have moved in this direction. Additionally, the California PUC recently adopted resource adequacy requirements for all load serving

entities and included demand response as qualifying resources.

E. Equitable treatment of demand response resources in regional transmission planning and operations

- ***What is the status of including demand response within regional transmission planning and operations?***

The regional system operators (e.g. ISOs and RTOs) have demonstrated aggressive leadership on demand response and for the most part include demand response in both planning and operations. These entities have, however, undertaken such DR efforts through the creation of programs, in some cases akin to traditional DSM programs that have been offered by utilities to their customers.

Demand response is not systematically integrated into resource plans – transmission or supply plans. Importantly, however, when open solicitations (open to expanding existing generation, new generation or demand response) have been held, such as ISO NE SW CT Gap RFP in 2003, demand response has been seen as the most economical solution. Therefore, the potential for a significant role for demand response is certainly likely if or when the competitive playing field is simply opened up to the best available solution.

- ***Have demand response resources been examined during the development of regional transmission plans, and to what extent?***

The regional system operators have increasingly included demand response resources in their planning efforts. DRAM assumes that these entities as well as other entities responsible for transmission planning within their service territory or area will provide responses to this question.

- ***Do current North American Electric Reliability Council (NERC) standards and regional reliability council rules accommodate the use of demand response as an alternative to building more transmission infrastructure, building generating capacity, or generating/purchasing more power?***

DRAM has no comment at this time.

- ***In regional transmission operations, such as RTOs and ISOs, what demand response resources are currently available? Under what circumstances are these resources called upon and at what level (kW/kWh)?***

DRAM has no comment at this time.

F. Regulatory barriers to improved customer participation in demand

response, peak reduction, and critical period pricing programs

DRAM believes that Section 1252 of EPACT essentially provides a national framework for the planning, assessment and deployment of DR across the U.S. While much discretion is left to States as to how to implement certain parts of 1252, DRAM believes the message from 1252 is clear – it is time for the nation and its various jurisdictions to collectively and simultaneously move on demand response. Over the next two years, that should happen as States implement EPACT and decide how best to deploy DR technologies and implement demand response pricing and programs as well as fully integrate them into retail and wholesale markets.

The important ingredients needed to bring demand response forward can vary by type of demand response and also by type of market. A large amount of demand response can be quickly developed in some cases and in some geographic areas by simply putting in place a delivery structure that includes payments for DR as a capacity resource. In other cases, policy makers need to provide an incentive for technology deployment, in a manner similar to what has been done to accelerate the introduction of many other types of energy options. One example is energy efficiency and renewable energy. They have achieved their success to date in large part due to government policies that provided specific incentives in these areas.

- ***What wholesale and retail regulatory barriers exist to improving customer participation in demand response?***

A large barrier is the lack of connection between wholesale and retail markets. Even in cases where wholesale markets and competition exist, the vast majority of customers in those areas may not be seeing any type of price that indicates any fluctuation in market prices based on time-of-day or other factors.

Another major barrier is the lack of strong financial incentives for utilities. Utilities have traditionally made more money by investing in rate base, i.e. building power plants. Demand response requires fewer plants. Regulators should provide direct financial incentives – rate of return bonuses – to provide the proper incentive for demand response. The incentive should apply to both the extent of demand response (MW) and the enabling infrastructure (e.g. advanced metering).

- ***What regulatory barriers exist to improving customer participation in innovative time-based rate programs, such as critical peak pricing?***

One of the major barriers is institutional in nature. Despite a large amount of evidence and research results that indicate that customers will accept and

even welcome time-differentiate rates, including from a wide variety of jurisdictions and customer types, many state regulators continue to express concern that customers may not accept such rates.

Another regulatory barrier can also be described as “institutional”. Regulated distribution companies, whether those still within a vertically regulated structure complete with generation or those that are independent “wires” companies, need to have some degree of certainty that, where necessary, capital investments made can be recovered and loss of revenue and profits due to a “throughput” linkage is also addressed. Moreover, it may be a question not only of making utilities whole but also providing them with incentives to undertake and implement such pricing programs such that they are able to move faster to implement such.

The impact of this lack of financial incentive for utilities, which have the ability to make all of the elements of such programs work together well (including marketing, customer education, equipment deployment, billing, information, etc.) should not be underestimated.

- ***What are the drivers and disincentives to customer interest in participating in demand response or critical period pricing programs?***

Among the biggest drivers may be utility support, simplicity (especially avoiding written contracts and long-term commitments), program stability, and ease of participation. The biggest disincentives may include the opposite of these: utility disinterest, complexity, frequently changing programs, and difficulty of participation

An obvious driver for customer interest is the opportunity to use the program to reduce their electricity costs. The greater the price differential there is between pricing periods, the greater the opportunity that will exist for savings. Other drivers include customer interest in getting the information about their usage that such programs provide. Customers have also indicated that they like having the technology that such programs normally include; this can range from information technology to control technology. As noted, a major disincentive is the lack of support and education to assist the customer in making the transition to a dynamic pricing or other demand response program.

- ***Do start-up costs limit the number of participants in demand response programs? If so, how should this issue be addressed?***

Start-up costs for demand response in many cases include some type of technology cost. Such an investment, even if proven to be cost-effective to implement, can still be a limiting factor in the size or ramping up of a DR program. This issue can be addressed in a number of different ways, including providing tax incentives for DR technology, allowing use of

system benefit funds or including customer payments that are applied to the technology.

- ***Does jurisdictional uncertainty between state and federal regulation create barriers to demand response programs?***

The separation of jurisdiction on wholesale and retail rates is an enabling factor to the disconnect that occurs in many areas of the U.S. between the wholesale market and the retail market.

In states where the restructuring of the electricity market is still underway, policy makers should ensure that energy resource procurement structures and mechanisms are put in place that provide symmetrical treatment of both conventional supply and DR. This should include some type of capacity payment and a long contract term that provides the certainty that developers of either type of resource require. In the case of DR, states should also take action to create opportunities for DR procurement aimed at the large blocks of customers who have not yet entered the competitive market. With utilities in the position of procuring peaking resources for such customers, the opportunity exists to introduce DR, not only as peaking resources, but also as a new option that will help move customers to transition to the marketplace.

- ***Are there regulatory or other barriers to participation of third-party curtailment service providers in ISO/RTO demand response programs? Are current settlement and payment procedures adequate for participation by these third-party entities?***

A number of barriers to improved participation include:

1. Absence of fair and full value for capacity being reliably delivered
2. Lack of clear event triggers that recognize both the needs of the system operators and the needs of end users e.g. if emergency capacity demand response is needed then only call events when last line of defense against blackouts similarly if peak demand avoidance is the desired outcome, the trigger event should be geared directly to days when peak load might be hit
3. Lack of ability for third parties to provide DR services; too often utilities restrict ability of third parties to participate in DR programs limiting their program success. This is especially counterproductive since third parties are often best positioned to take on risk of performance of individual assets and therefore are willing to accept penalties for non performance
4. Lack of program staying power; demand response programs change far too frequently, making it impossible for end users and others to plan.
5. Absence of a requirement for appropriate technologies to monitor performance during events and establish reasonable, clear methodologies for determining performance baselines

- ***Given that distribution companies may no longer own generation or be a supplier of last resort, has their incentive to provide demand response been reduced? If so, what alternative mechanisms or policies should be considered to provide incentives to these distribution companies to implement demand response?***

In such a case, the incentives may have changed but not necessarily been reduced. Whether a reduction exists will depend on the specifics of a given situation. Wires-only companies can use demand response to address grid constraints on a localized or targeted basis. Using DR in such a manner can allow new T&D facilities to be potentially deferred and optimized.

It is also the case that many distribution companies still find themselves as the primary load serving entity to their customers as a result of the transition to a restructured competitive retail market not having occurred as quickly as expected. In such a situation, all parties – state policy makers, wires companies, and retail marketers – should have an incentive to connect the wholesale and retail markets and provide transition mechanisms that facilitate customer migration. By providing time-differentiated pricing to customers that have not yet made that migration and who are still on default service, customers will begin to understand the choices that the market can provide and begin to make choices about the type of electricity service that

they wish to have.

With many states not having restructured their electricity market, delivery of demand response will most likely and most appropriately be accomplished via utilities directly and indirectly (by contracting with DR providers) providing DR to their customers. Even in restructured states, however, utilities do have and are likely to continue to have a role in the delivery of demand response. They are the most logical and economical place for the deployment of advanced metering and other DR technologies. They are also still the provider for the lion's share of mass market customers.

Utilities in most cases have a number of barriers (e.g. reduced throughput, rate/price caps, lack of regulatory certainty, etc.) and few if any incentives to invest in DR. State policy makers should move quickly to remove these barriers, even if only with respect to DR investments such as advanced metering. Incentives should also be put in place such as performance based rates or ROE incentives linked to DR target achievement. These incentives should be structured to allow the utilities to undertake long term contracting for DR resources.

- ***Do current retail rate structures, which are largely based on volumetric rates, create a disincentive for distribution company promotion and implementation of demand response? If they do, how can this disincentive be reduced?***

Yes. This issue, often referred to as the “throughput” issue, is a disincentive for demand response, just as it has for years been a disincentive for utilities to provide and implement energy efficiency programs.

- ***What are the drivers or disincentives to load-serving entities offering aggressive demand response programs?***

Drivers include reducing LSE supply costs and providing attractive customer options.

The throughput issue, as noted in the previous response, is a disincentive. Cost recovery is also a legitimate issue. But making a utility “whole” is not the only question to be addressed. Utilities should be provided with incentives that provide them with a revenue/profit increase for undertaking demand response. This can come via options such as performance based rates or from options such as those where a utility is provided with a boost to its earnings for achieving certain demand response targets.

The key disincentive for non-utility LSE's can be the can be lack of cost-effective access to enabling infrastructure; without capturing utility scale economies and utility operating savings, it is not economically possible for

a non-utility LSE to install advanced metering to make such programs possible. Note that utility scale economies include the ability to amortize infrastructure investments over 15 to 20 years, which is not possible for a non-utilityLSE which may lose the customer in a matter of months.

III. Conclusion

DRAM commends the Commission for its work in creating a framework for a nationwide assessment of demand response that will create the necessary foundation of information that will allow the use of demand response in the U.S. to be accelerated and increased.

DRAM looks forward to providing further comment at the Commission's January 25th Technical Conference on Demand Response and to being a resource to the Commission as it moves beyond that event to implement the assessment.

Any questions regarding these comments should be directed to:

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Attachment A

Demand Response and Advanced Metering Coalition (DRAM)

Definitions

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Demand Response

Demand response refers to the reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling.

Dynamic Pricing

Retail prices for energy consumed that offer different prices during different time periods and reflect the fact that power generation costs and wholesale power purchase costs vary during different time periods. Types include Time-of-Use Pricing, Critical Peak Pricing and Real-Time Pricing.

Time-Of-Use Pricing

Energy prices that are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year (summer and winter season). Prices paid for energy consumed during these periods are pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period, or reducing consumption overall. The time periods are pre-established, typically include from two to no more than four periods per day, and do not vary in start or stop times.

Critical Peak Pricing

A type of dynamic pricing whereby the majority of kWh usage is priced on a TOU basis, but where certain hours on certain days where the system is experiencing high peak demand are subject to higher hourly energy prices that reflect market conditions for peak generation and delivery during peak demand periods. These

critical period prices may be known to electricity customers under conditions such as “day-ahead” or “hour ahead” and are typically employed a limited number of times per year.

Real-Time Pricing

Energy prices that are set for a specific time period on an advance or forward basis and that may change according to price changes in the generation spot market. Prices paid for energy consumed during these periods are typically established and known to consumers a day ahead (“day-ahead pricing”) or an hour ahead (“hour-ahead pricing”) in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period, or reducing consumption overall.

Standard Meter

An electromechanical or solid state meter that cumulatively measures, records and stores aggregated kWh that is periodically retrieved for use in customer billing.

AMR

Automatic Meter Reading – system where aggregated kWh usage, and in some cases demand, is retrieved via automated means such as a drive-by vehicle, or walk-by hand-held system. .

Interval Meter

A meter that measures and records kWh usage on either predetermined or remotely configurable time intervals, where the intervals are in increments such as minutes or hours.

Advanced Meter

An electric meter, new or appropriately retrofitted, which is 1) capable of measuring and recording usage data in time differentiated registers, including hourly or such interval as is specified by regulatory authorities, 2) allows electric consumers, suppliers and service providers to participate in all types of price-based demand response programs, and 3) which provides other data and functionality that address power quality and other electricity service issues.

Smart Meter

A different term used to refer to an advanced meter.

Advanced Metering Device

A separate electronic device coupled to a standard meter that enables it to function as and meet the definition of an advanced meter.

Retrofitted Meter

A standard meter that has had an advanced metering device added to it.

Advanced Metering or Advanced Metering System

A system that collects time-differentiated energy usage from advanced meters via a fixed network system, preferably two-way, on either an on-request or defined schedule basis. The system is capable of providing usage information to electricity customers, utilities and other parties on at least a daily basis and enables them to participate in and/or provide demand response products, services and programs. The system also supports additional features and functionality related to system operation and customer service, e.g. outage management, connect/disconnect, etc.

Advanced Metering Infrastructure

The communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems which allows collection and distribution of information to customers and other parties such as competitive retail suppliers, in addition to the utility itself.

Emergency Demand Response Programs

Programs which are dispatched by system operators when system operating reserves drop to levels such that load reductions are needed to maintain short-term system reliability.

Economic Demand Response Programs

Programs which encourage demand reductions via price signals to energy users that reflect the higher costs of electricity production and delivery at times of system peak.

Load Management

A term used to refer to interruptible rates, curtailment programs and direct load control programs.

Direct Load Control

A system or program that allows utilities, other load serving entities, or demand response service providers to control user load via 1) directly cycling discretionary load of certain end uses, 2) directly turning off such loads or 3) implementing custom load control strategies that reduce peak usage.