A REGULATORY CONSTRUCT FOR DEMAND RESPONSE

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According to year-end 2011 findings published by the Federal Energy Regulatory Commission (FERC), in the United States the aggregate impact of DR is estimated at 58 GW, or 7.6 percent, of the peak demand, which is up 42 percent from two years ago. FERC views the potential for further cost-effective DR to reach as much as 20 percent of the system peak.

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INTRODUCTION

Books, dissertations, and other lengthy volumes have been written about the topics of demand response (DR) and its relatives demand side management (DSM) and energy efficiency (EE). The topic has been a source of interest for the electric utility industry for decades, and that interest has certainly been heightened recently due to the ongoing deployment of smart meters across the United States, which in many instances are being used, at least in part, to enable load-reduction activities. The benefits of these programs have been debated extensively in other forums, and there is general consensus within the industry that DSM programs can help stabilize electricity peak prices, enhance grid reliability, and reduce the need to build costly generation, transmission, and distribution facilities.

And yet, with all these documented benefits, load-reducing programs are still far from commonplace across the nation's utilities. The major stumbling block is the lack of strong financial incentives for utilities to engage in DR program development and the pervasive uncertainty in the regulatory arena that the investment will be recoverable. In fact, the unique regulatory challenges facing those electric utilities that have developed an EE, DR, or DSM program arguably have not received the same amount of analysis as other aspects of this field. And yet, ironically, from the point of view of electric utilities, effectively navigating through the regulatory maze, whether on the state or federal level, can be one of the determining factors in whether a load-reduction program will succeed or fail.

DR has policy implications and impacts for both the wholesale and retail electricity markets. In fact, many would argue that integration of both wholesale and retail market structures will be a key to the success of DR. The primary objective of this white paper is to provide electric utilities with an overview of the regulatory challenges—and successful cost recovery strategies—in state public utility commission (PUC) proceedings. The specific reference to DR is intentional; the limitations of a single white paper do not lend themselves to address DR and EE. However, the potential role that DR alone can play to decrease peak prices and, in general, electricity price volatility is quite significant. According to year-end 2011 findings published by the Federal Energy Regulatory Commission (FERC), in the United States the aggregate impact of DR is estimated at 58 GW, or 7.6 percent of the peak demand, which is up 42 percent from two years ago. FERC views the potential for further cost-effective DR to reach as much as 20 percent of the system peak (perhaps as much as 188,000 MW by the end of the decade, if technology can be aligned with the right policy and economic incentives).

Moreover, regardless of the form of DR that a utility might seek to pursue, the reasons for doing so are fairly consistent: there is consensus in the electric industry that DR can create both system and societal benefits by reducing the need for traditional generation sources. In fact, EPA restrictions on traditional power supplies, and the onerous challenges of siting new power plants in most U.S. locations, have collectively called into question the future viability of nuclear, coal, and renewable sources. The alternative of DR has become increasingly attractive to utilities when DR gains equal footing in among other integrated resource planning options. However, the decision to participate in a DR program is driven primarily by economics, or, put more simply, when benefits of the DR program are greater than costs.

One of the primary obstacles for DR, not surprisingly, is the regulatory limitations that have been created at both the federal and state levels. I would argue that the potential contributions that DR can make to the nation's energy portfolio have been severely constricted by a number of regulatory factors that I will address in this white paper. From a positive standpoint, there are some advances on the state level that show promise for offering templates to combat what have been regulatory obstacles, and along with these advances the following topics will be covered in this white paper:

- The primary federal and state regulatory barriers that continue to impede the growth of DR;
- The regulatory questions that each state PUC must address when evaluating DR potential in their state;
- Cost recovery strategies on the state level, such as decoupling and elimination of the "disincentive throughout," which if left unaddressed can diminish the potential for DR due to the uncertainty it creates for utilities;
- Other regulatory incentives and disincentives that are influencing the growth of DR;
- A regulatory "best practices" examination of Missouri, in which new legislation and regulatory stipulations have defined arguably the most favorable market conditions for DR that exist in the U.S. today; and
- Strategy recommendations for utilities that are involved in a regulatory proceeding seeking approval for DR programs.

DEMAND RESPONSE DEFINED

Although EE and DSM will not be covered at the same level of detail as DR in this white paper, it is difficult to have any discussion of DR without first establishing some agreed-upon definitions, and within those definitions to make distinctions and comparisons among the three related load-reducing approaches. I appreciate that there are different interpretations of what constitutes DR, and how DR correlates with DSM and EE, so at the onset I would like to establish the following baseline definitions on which I will rely for this analysis.

- Demand Side Management (DSM): Any program conducted by a utility to modify the net consumption of electricity on a retail customer's side of the meter or otherwise influence customer consumption patterns to match current or projected capabilities of the power supply system. DSM consists of two major components: Energy Efficiency and Demand Response.
  - Energy Efficiency (EE): Activities, programs, or other efforts that seek to achieve megawatt-hour (MWh) savings over a long period of time. EE refers to permanent changes to electricity usage through installation of or replacement with more efficient end-use devices or more effective operation of existing devices that reduce the quantity of energy that is needed.

- Demand Response (DR): A term used for programs designed to encourage end-users to make short-term reductions (typically a duration of one to four hours) in energy demand in response to a price signal or some other trigger initiated by the load-serving entity (LSE) or electricity grid operator. The objective of all DR programs is to decrease peak demand to off-peak periods.

DR itself comes in many flavors, and DR programs are evolving and changing at a rapid pace. Within the universe of DR options, there are a number of different ways of referring to the various strategies that are used to encourage and enable customers to make short-term changes in their behavior to create reductions in energy demand. Further, there are different sub-categories of DR and valid distinctions that can be made between "price-based DR" and "event-based DR"; "energy DR" versus "economic DR"; and certainly among the many varieties of DR programs that are developed for residential and commercial & industrial customers. For simplicity's sake, and to enable the focus on regulatory issues, this white paper will use the prevalent definition that has been offered by FERC, which establishes two primary types of DR programs:

- Price-based programs: Dynamic pricing structures, which include time-of-use rates, critical-peak pricing, and real-time pricing; and peak-time rebates.
- Incentive-based programs: Payment-based programs, initiated by an LSE, which include direct load control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary services market programs.

Whether active in the retail or wholesale markets or both, utilities that are pursuing DR typically must choose between price- and incentive-based programs. Other studies have shown that the degree to which a utility is seeking a significant revenue source from DR may be the primary deciding factor in whether it adopts the more innovative (and complex) price-based programs.

Consistent with FERC's definition, another way of categorizing DR programs is to think of price-responsive versus controllable DR. Using the dynamic pricing structures that are referenced above, DR occurs when end-use customers are exposed to these prices and are able to curtail their usage patterns based on a consideration of the dynamic rate against their consumption preferences. Apart from the benefits afforded by participating in a dynamic pricing structure, end-use customers are not provided an explicit payment as compensation for curtailing their load in price-responsive DR programs. In controllable DR, an LSE and an end-use customer enter into an agreement whereby the LSE can curtail power usage by the end-use customer (through measures such as direct load control) under certain circumstances that have been well defined. In controllable DR scenarios, the end-use customer does receive an explicit incentive payment for curtailing their load.

Regardless of the specific nuances of its sub-categories, generally speaking DR takes place when a customer changes their consumption patterns in response to a well-defined stimuli, whether it be a price-based tariff (such as TOU or CPP) a non-rate-based economic incentive such as a rebate; or some other term of contract in which the customer agrees to have its load reduced for a specific period of time when a well-defined and agreed-upon set of circumstances occur (whether those circumstances are supply shortages or increased prices). In fact, while DR programs can vary greatly among the different utilities that offer them, one common denominator is that DR programs are focused on short-term or temporary customer responses (whether they be manual or automated) that result in MWh savings.

It is becoming increasingly common to think of DR and EE as siblings under the parent of DSM. In fact, many legislative or regulatory directives have stated that utility DR and EE programs should be coordinated in order to achieve the most significant load reductions. California is one example; seven years ago, in 2005, the California Public Utilities Commission (CPUC) directed the state's three IOUs to integrate their EE and DM programs. Connecticut is another example; even if there is not a mandate to integrate DR and EE, legislation in Connecticut requires that both be on equal footing.

While the focus here is on regulatory strategies for DR on the state (retail) level, it is unwise to completely detach the retail sector from what is happening at the wholesale level. In fact, I would posit that most of the significant growth of DR to date has taken place in organized wholesale markets that are administered by ISOs/RTOs (the third-party independent operators of transmission systems) and this growth has been focused on incentive-based programs as defined above. While a discussion of the unique programs, products, and services administered by the ISOs and RTOs in North America can become complex rather quickly, in general in wholesale DR programs, customer load reductions are aggregated from retail customers by independent marketers, and then provided to the wholesale provider, such as an ISO/RTO, in exchange for some type of incentive-based payment.

Within the seven RTOs that are currently operating in the United States (CAISO, ERCOT, MISO, ISO-NE, NYISO, PJM, and SPP), to one extent or another DR is playing a role in organized wholesale markets—as administered by the respective RTO—as a capacity resource, an emergency resource, a buy-back resource, or an ancillary services resource.

REGULATORY POLICIES

It is not surprising, given that it is a structural objective for DR on the wholesale and retail markets to be well integrated, that policymaking has been primarily focused on the federal level. That is now starting to change somewhat as individual state regulatory commissions create some groundbreaking regulatory treatments of DR in new orders, examples of which I will discuss in this white paper. However, in examining the regulatory policies that have shaped the DR market potential, first and foremost it is FERC's policymaking that must be considered.

The first impetus in the current wave of DR policymaking came from federal legislation. Section 529 (a) of the Energy Independence and Security Act of 2007 required FERC to conduct a National Assessment of

Demand Response Potential and report to Congress on a number of key findings: 1) an estimation of DR potential in 5- and 10-year horizons and on a state-by-state basis; 2) an estimation of how much DR potential can be achieved within those timeframes; 3) what incentives may need to be created to enable DR growth; and 4) identification of barriers that have prevented a non-discriminatory playing field for DR and recommendations for overcoming those barriers. As part of these federal requirements, FERC has made its projections of DR that were referenced above.

It is also the FERC that first affirmed the importance of DR in wholesale energy markets when it issued Order 719 in October 2008. The order made changes in the ways that RTOs or ISO operate in the wholesale markets and outlined requirements that RTOs/ISOs must accept bids from DR resources in their markets for certain ancillary services. Taking this concept even further, in the final rule related to this proceeding, which was finalized in March 2011 and became known as Order 745 (or, more specifically, Order 745-A), FERC has attempted to create an even playing field for DR by creating a uniform compensation scheme for DR (and removing the compensation barriers) in participating in wholesale energy markets. Specifically, now when a DR resource participates in a wholesale energy market administered by an RTO or ISO that DR resource must be compensated at the market price for energy, referred to as the locational market price (LMP), as long as it meets some set criteria for cost-effectiveness, which were created to determine the DR resource's impact on remaining loads. The other key aspect to Order 745 was that ISOs must also establish a net benefits test to determine when DR are cost-effective and must allocate the costs of DR to all customers who benefit from the curtailment service.

FERC Chairman Jon Wellinghoff created some controversy in the industry earlier this year when he suggested that DR might be worth even more than traditional generation. Wellinghoff indicated that FERC was exploring the idea of paying up to 1.4 times more the amount paid to generation in capacity markets, to reflect the locational and fast-response abilities of DR. It should be noted that both these comments and FERC's fundamental ability to create rulemaking on DR is being hotly debated presently. Claims have been made before the U.S. Court of Appeals that FERC does not have jurisdiction to regulate the compensation of DR because it is a retail activity. Petitioners in this filing include the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association, who have argued that FERC's approach will over-compensate participating retail customers, unduly discriminate against wholesale power producers, and distort the nation's energy markets.

Although it is outside of this scope of the present discussion to delve deeply into this topic, how to measure DR is a pivotal policy issue at the federal level. As both DR and EE resources are bid into wholesale forward capacity markets, compensation issues of how to reward those resources based on usage or kilowatt-hours reduction—and the related challenges of how to measure what should and should not be included in those resources—are key parts of the broader debate over FERC's Order 745. And we should be clear that evaluation, measurement and verification (EM&V) policies for DR are not only a federal issue; standard definitions for estimating program savings at the state level have also become increasingly important so that all entities reporting on energy savings created by DR programs are reporting in a consistent manner. Individual states play a key role in creating DR rules and regulations; in fact, there is little question that the full potential of DR will not be achieved until some key policy advances are made at the state level. However, there is tremendous inconsistency when looking at the approach being taken on a state-by-state basis toward creating DR policymaking. It is impossible to generalize about state-based policy trends, but there are clearly a number of barriers that exist on the state level that all state PUCs and utilities need to focus on when examining the viability of utility DR programs in their respective jurisdictions.

REGULATORY BARRIERS

With this brief overview of the components of DR, we can now turn to the focus of this white paper, the regulatory strategies that have proven successful in creating cost-effective utility programs and the barriers that have historically been an obstacle for implementing those strategies. The end result of these regulatory dynamics is that, despite the extensive documentation supporting the benefits of DR, the vast majority of utilities across the United States do not have what could be called robust DR program offerings available to their customers…and further have not designed a long-term resource portfolio in which demand-side resources have equal or comparable footing with more traditional resources. The reasons for this lack of growth in the DR market can be directly linked to regulatory barriers, which can originate from specific market rules or the unique features of a market or program design, and can also originate on the retail or wholesale levels.

The six (6) regulatory barriers that I would argue are having the greatest negative impact on DR programs are the following:

1. Deployment of smart meters is not the commonplace across utility populations—at least not yet.
2. Dynamic pricing structures that enable DR programs are not generally in place across the United States.
3. The traditional regulatory framework does not lend itself to DR investments by the nation's utilities.
4. There is a disconnect between electricity retail markets and wholesale markets, which has created regulatory limitations for utilities pursuing DR.
5. DR still does not generally have "equal footing" along with traditional supply-side generation sources within the context of utility integrated resource planning.
6. The uncertainty of how to treat and measure DR, both on the state and federal levels, has created stagnated growth of the market.

Let's examine each of these barriers in greater detail:

1) Smart meter penetration. Although I run the risk of "preaching to the choir" with the following statement, I will say it nonetheless because it so important: smart meters (or advanced meters as some prefer to call them) play a critical role in supporting DR programs. Why is that the case? Advanced meters allow kilowatt-hour usage to be tracked on a real-time basis and are typically integrated with an advanced metering infrastructure (AMI) communications systems that enables remote meter reading and two-way communications between the meter and an LSE's back office. This is a good thing. However, the problem is that deployment of advanced meters in the United States is far from prevalent as we approach the end of 2012. According to a report last year from FERC, referencing data from the Institute for Electric Efficiency (IEE) and the U.S. Energy Information Administration (EIA), the penetration rate for smart meters has increased but is still nowhere near what we would call a "mass immersion" state. Back in 2009, the penetration rate was about 6.5 percent for smart meters in the U.S., which amounted to approximately 9.6 million advanced meters having replaced the total of 148.4 million meters in the country. That penetration rate had increase to about 13 to 18 percent as of late 2011 (data for 2012 is not yet available). What this means within the context of a discussion of DR programs is that, while there little doubt that advanced meters are coming, the fact that they are not here for the majority of customers places a limitation on the prospects for DR.

Certainly, it is true that advanced meters are not essential to implement every type of DR program. For example, a customer's load can be remotely controlled by a utility or third party in return for the customer receiving some form of payment. However, generally what is necessary to implement a more robust DR program is the ability for customers to reduce or shift their peak electricity demand and to correlate that reduction or shift with an incentive offered by their LSE. Advanced meters play a key role in this due to the interval basis on which they operate, which in turn allows for different periods on different days to be priced differently. So there can be very little argument that advanced meters are a necessary ingredient in the recipe that will enable DR to reach its full potential.

2) Dynamic pricing structures. As previously mentioned, dynamic pricing simply means those rates structures such as TOU, CPP and RTP. Dynamic retail pricing are important because they enable transparency between retail prices and wholesale prices, and create customer price sensitivity as wholesale prices fluctuate over the course of the day. However, dynamic pricing rates are still the minority among rate options across U.S. electric utilities. Most residential and commercial customers through the U.S. are still being billed at traditional "flat" or "fixed" rates, which are set at an average cost, do not vary dynamically with changes in overall supply and demand conditions and, therefore, offer no price signals to customers. Since customers on flat or fixed rates do not see price signals to reduce use when demand and prices are high, they have no incentive to reduce their consumption. Having insights into the fluctuation of prices is one of the prerequisites on which to build a DR program.

A 2010 survey conducted by the FERC indicated that only about 1 percent of residential consumers are billed based on time-of-use rates. Data obtained from the National Association of Regulatory Utility Commissioners (NARUC) suggests that a large number of utilities in over half of the states in the U.S. have conducted pilot programs to test opportunities for dynamic pricing and to evaluate the potential for deploying full-scale programs. But to date, a relatively small proportion of utilities have elected to implement ongoing dynamic pricing programs. There is certainly a correlation between the lack of dynamic pricing structures and the slow penetration of advanced meters; flat rates may be the only option that a customer has in the absence of meters that can record time-differentiated usage. Utilities and regulatory commissions that are considering the implementation of ongoing dynamic pricing programs will need to decide if the programs will be mandatory or voluntary, which naturally also has an impact on the portion of the customer population that will be eligible to participate in dynamic pricing programs and, consequently, the DR programs they enable.

3) The traditional regulatory framework. While regulatory models for the treatment of DR and EE can vary greatly from state to state, there is a common denominator among the various approaches, and that is that the regulatory framework that has been in existence for decades was simply not constructed to encourage DR programs. That sounds like a bold statement but actually it is rather elementary. What it means is that under traditional utility regulation, utilities have earned a rate of return on investments in generation, transmission, and distribution infrastructure. Further, utilities have earned revenue based on the volume of energy delivered to customers, so put simply the more energy they sell, the more revenue they can earn. And, since traditional supply side generation has been associated with more reliable guarantees of cost recovery, utilities have had little motivation to seek out alternatives. This regulatory framework has not provided much of an opportunity for DR to emerge, given that the objective of DR is to use less energy. While the deficits of this framework have been acknowledged for some time, unfortunately steps taken to create parallel incentives for DR and EE investments at the state level have not kept pace with the need for load-reducing approaches.

Diving down deeper into this regulatory framework, the specifics of cost recovery mechanisms have not been particularly appropriate for DR programs, even if utilities had opted or been mandated to pursue to them. Under traditional ratemaking, regulators establish rates that utilities can charge customers based on a historical test year with some allowance for forward-looking cost changes. Utilities are allowed to recover their costs through a combination of rate bases that are updated through general rate cases (the schedule for which varies among specific state PUC and specific utilities) and cost trackers or other adjustment mechanisms that are created to address the discrepancies between estimates based on a test year and actual expenses that are incurred. In this ratemaking regime, a utility’s revenue has been directly tied to kilowatt-hour sales of electricity, so the incentive is created for a utility to generate more sales to cover its associated costs. The term “throughput incentive” has been coined to describe this phenomenon. DR and EE are fundamentally inconsistent with this approach and in fact create a “throughput disincentive” as they reduce a utility’s revenues, even in cases where the direct costs of DR and EE investments are recoverable by the utility.

Investor-owned utilities also have a financial responsibility to maximize shareholder value. Thus, when faced with two investment decisions – such as the choice between building a power plant or investing in DR and EE – a prudent choice is for the utility to select the option that is most profitable. Acting in any other way can negatively impact its ability to conduct business and attract investor capital. Absent a specific cost recovery mechanism, utilities would effectively be penalized, through a lower earned return on equity, by making incremental and prudent investments in new and innovative programs whose costs aren't already reflected in rates. I will speak to the steps that are being taken to address this dynamic later in this white paper, but the essential point now is that traditionally utilities are not only not given incentives to invest in DR, they typically will lose money from the investment in current regulatory structures that are commonly in place at the state level.

4) Unequal treatment of EE/DR. Historically, most regions of the U.S. have satisfied their load requirements through more traditional generation and transmission planning activities that are conducted by individual utilities, and are outlined in those utilities' long-term integrated resource plans. Some states (for example, California, Hawaii, Nevada, and New York) have taken steps to mandate that utilities include or at least consider demand-side resources as part of their resource plans, either as an adjustment to the long-term demand forecast or as an explicit resource, but the vast majority of states still do not include this requirement. There are a variety of reasons why states and utilities would not include demand-side resources in long-term resource plans, but the important point is that many utilities, in the absence of a mandate or incentive, simply do not consider EE/DR options when contemplating future resources.

5) The disconnect between the wholesale and retail markets. As previously mentioned, DR is primarily a retail-market based issue for which the greatest determining factors of its success will be found within state regulatory policies. However, the correlation between retail and wholesale markets is an important component in the discussion of regulatory policies for DR programs, and presently that correlation is impacted by what is viewed as a disconnect between wholesale and retail electricity markets. Specifically, that disconnect boils down to the fact that retail prices are set at an average cost while wholesale prices reflect market competition. As mentioned above, the discrepancy between these pricing structures limits a retail customer's ability to effectively respond to price changes at the wholesale level that are not accurately reflected in retail level prices. However, there is a broader issue that also speaks to the disconnect between the two markets and that is the level of integration between states and ISOs/RTOs.

Despite the operational maturity of the seven ISOs/RTOs in the U.S., the extent to which retail and wholesale markets are effectively integrated, which is typically determined by whether or not the region in which a utility resides is a participant in an RTO or ISO. The seven ISOs/RTOs serve about two-thirds of electricity consumers in the U.S., but the fact that an organized wholesale market exists does not necessarily mean that eligible LSEs and customers are participating in that market. For example, ISOs/RTOs may develop a market-based product for DR but have difficulty with implementation if these products require an associated retail level mechanism under the jurisdiction of the state.

Moreover, this disconnect requires the attention of both state and federal regulators, and this issue is certainly on the radar screen of FERC and NARUC. While states have primary jurisdiction over retail demand response, DR plays a role in wholesale markets under FERC jurisdiction. Thus, there is collective agreement that greater clarity and coordination between wholesale and retail programs is needed.

6) The uncertain treatment and measurement of DR. There are two aspects of this regulatory barrier that are important to consider. First, on the state level, utility energy procurement rules generally do not classify energy efficiency as a "source" of energy, thereby preventing utilities from pursuing it under their standard generation and procurement operations. This means that EE and DR are unfortunately overlooked in many utilities' integrated resource planning (IRP) for future years. Some utility commissions have mandated that utilities in their state include EE and DR in IRPs, but many have not. And even when there is a mandate to include load-reducing strategies in long-term planning, the inequitable treatment of EE and DR when compared to traditional supply-side resources can create regulatory uncertainties, which obviously most utilities would want to avoid.

On the federal side, this barrier concerns ambiguities around how DR should be measured and verified. Measurement and verification refers to the application of statistical and load research techniques to measure and verify the load reduction impact resulting from the utilization of a DR program, or more specifically the value of DR load reduction that is achieved through a DR event. A particular challenge in measuring and verifying demand response is accounting for the highly variable load and weather-sensitive load changes. Measurement can be reported in MW, hourly kW, peak kW, etc. and may further be reported in a variety of intervals including 15, 30, 60 minute and total event duration. The barrier exists because there is presently a lack of agreement on the appropriate M&V standards at the federal level.

FERC and the Department of Energy have formed workgroups to study ways to measure and verify DR and assess its cost effectiveness in power markets. At issue is how to estimate effectively a customer's baseline electricity use. At the wholesale level, participants in DR programs typically measure their reductions by comparing actual meter readings against the customer baseline (what the metered load would have been without the reduction in demand). However, RTOs and ISOs use various baseline methods to estimate consumption without DR. Efforts are underway at both the state and federal levels to standardize baseline estimates.

Also, in April 2012 FERC proposed to amend its regulations to incorporate by reference the North American Energy Standards Board (NAESB) business practice standards for the measurement and verification of DR (and energy efficiency) resources participating in organized wholesale markets. The proposed DR standards would add specifications to existing standards in several areas, including meter data reporting, advanced notification, telemetry, and meter accuracy. Together the proposed and existing business practice standards provide a framework that can be used to develop performance evaluation methodologies for specific DR services, but do not specify detailed characteristics of those methodologies.

COST RECOVERY FOR DR

On the state level, no other issue has created the disincentive for utilities to pursue to DR more than the uncertainty around how associated costs will, or even can, be recovered. In fact, this is arguably the number-one consideration within DR proceedings at the state PUC level, as no utility will pursue DR without reassurances that it can recover its related costs. Further, many utilities seek or demand dollar-for-dollar cost recovery, meaning that 100 percent of their DR investment is recoverable, and without such guarantees believe that DR is a non-starter.

There are a number cost-recovery issues that utilities and state regulators will face as they examine the prudence of DR programs. For instance, some utilities have argued that along with recovery of DR program costs, they should also be entitled to recovery of their avoided supply costs (or "avoided costs"). By generating energy savings through DR, a utility typically creates avoided costs that are not passed on to ratepayers. The argument that has been posited in some utility regulatory proceeding (e.g., Duke Energy) is that the utility should be compensated for demonstrated demand-side savings by receiving a percentage of its avoided supply costs. Further, in order to ensure that DR investments can play on a level playing field with more traditional generation investments, some utilities have lobbied for "rate-of-return" adders in which DR investments would earn a higher rate than traditional supply-side investments.

Along with cost recovery, performance-based regulation, which has already gained momentum in the spectrum of AMI and smart grid, now appears to be extending to DR programs as well. What this means is that state PUCs may, on condition of their approval for a utility DR program, establish certain targets, incentives, and penalties that the utility will face for the duration of the DR program. Cost recovery and the sharing of benefits are usually tied to these benefits, with a balance between creating "carrots" (i.e., incentives) versus "sticks" (i.e., penalties) that depends greatly on the state PUC in which the regulatory proceeding is taking place.

The incentives can be referred to as "shared savings," meaning that the utility would receive a percentage share of the energy savings that result from a DR investment. How this might work is that a utility could receive a pro-rated percentage of the incentive for achieving, for instance, 70 to 110 percent of an established target, or additional rewards for achieving more than 110 percent of the target. On the other side of the coin, penalties might be put into place that will result in fines affixed to the utility if it does not meet its established target goals for the DR program.

Other cost-recovery related issues that utilities and PUCs are facing in state regulatory proceedings include:

- Equity among customer classes (e.g., do low-income customers obtain the same level of benefits if they have less load to shift?)
- Fair apportionment of costs across all customer classes (i.e., related to the above bullet, if some customer classes do not have an equal opportunity to benefit from DR savings, should they be required to bear costs for the program?)

- Simplicity of the rate design (i.e., more complex rate designs may dissuade customers from participating in a DR program.
- How can utilities find the right balance between rate structures that will enable cost recovery in already-complex rate design scenarios, while creating rates that are easy for end-user customers to understand?)

DECOUPLING

Perhaps no other regulatory strategy has attempted to address the challenge of removing disincentives to utilities that otherwise would be less inclined to pursue DR than the concept of "decoupling." In fact, it could be argued that without decoupling as part of the regulatory equation at the state level, DR is a non-starter for most utilities. However, some utilities may still be unclear on what decoupling options may be available to them, or what the term even means.

Thus, as an introduction, decoupling is a generic term used to represent a variety of methods for severing the link between revenue recovery and sales in utility regulatory proceedings. As previously noted, the traditional regulatory structure of the electric utility has created a scenario in which utilities generate more revenue the greater sales they produce, and within this structure DR is counter-intuitive to say the least. So how does decoupling address this conundrum? It provides a different approach toward cost-recovery than is normally found in traditional "cost-of-service" (COS) theory of regulation, under which a utility has been granted approval to recover costs incurred in providing service to its customers based on the operating experience of a typical 12 month period (the utility's "rate of return" on its investments). Also within COS regulation, a utility's revenue requirement is determined by adding the total of its expenses and the allowed return on investment that is set by the state PUC. The revenue requirement is then divided by the amount of sales in the test year to derive what is called "throughput based rates." In a rate case, test-year sales and operating costs are typically adjusted to reflect "normal" weather. Regardless of the type of test year used, the resulting prices are what customers pay per unit of electricity or gas that they use until rates are reset with next rate case. This scenario makes it difficult for a utility to increase its profits by lowering sales; conversely, the more sales generated, the more likely the utility will be to meet or exceed its revenue requirements. Again, this leaves little opportunity for DR to be developed.

Decoupling allows utilities to actually encourage consumers to use less electricity without adverse financial consequences. Decoupling does not change the traditional rate case procedure but, in its simplest form, adds an automatic "true-up" mechanism that adjusts rates between rate cases based upon the over- or under-recovery of target revenues. As in the traditional rate case, a rate is set by determining the revenue requirement and dividing it by expected sales. Then, on a regular basis, prices are re-computed to collect a target revenue based on actual sales volumes. Decoupling mechanisms can be designed to be adjusted on a monthly or quarterly basis, or some other regular interval.

One prominent example of how decoupling has been used in the context of DSM programs can be found at Duke Energy, which is in the process of merging with Progress Energy. Duke has a program known as Save-a-Watt that has been in place for about five years. Under the program Duke must seek to reduce electricity demand by a total of 2 percent by 2013 and 8 percent by 2020 through expanded energy efficiency DSM programs. An essential part of Duke's regulatory strategy for the Save-a-Watt program is to gain capital expense-style returns for investment in energy efficiency in the same way that is has for power lines and power plants. Decisions by the North Carolina and South Carolina regulators (two of the states in which Duke Energy operates) have partially decoupled Duke's earnings from electricity sales, which has permitted the utility to recover most of the lost revenue associated with this Save-a-Watt program. Specifically, the recovery plan that has been approved in these two states allows Duke to use a rate rider to recover 75 percent of the avoided costs associated with the Save-a Watt program and 50 percent of the avoided costs associated with more general EE programs. The incentives have enabled Duke to significantly expand its DSM program offerings since the program began.

Some decoupling proponents have argued that removing disincentives is not enough. They contend that the cost of efficiency programs should be included as part of the cost of service. Moreover, in order to make efficiency investments profitable when compared to other possible investments that the utility could make, such as power plants or transmission, performance incentives for efficiency would reward utilities that invest in successful programs by allowing them to earn an equivalent rate of return on those investments. On the other hand, some PUCs believe that a distinct decoupling or lost margin recovery mechanism is unnecessary because a properly defined performance incentive mechanism can indirectly address recovery of lost margin revenue, eliminating a disincentive and creating a balanced regulatory platform that will properly incent utilities to evaluate DR investments.

NEW BUSINESS CASE APPROACHES FOR DR

Another topic that is quite relevant to cost recovery in DR regulatory proceedings, and thus to this white paper, is the issue of creating a solid business case for DR. This topic could also warrant its own stand-alone white paper, but the alternative option within the constraints of this analysis is to look at what are new strategies for building a positive business case for DR around new smart grid technologies that are currently emerging and/or gaining momentum.

Most business cases for DR will be based on the foundational concept that incorporating DR programs during peak demand periods is a far cheaper alternative more traditional options, including the most common approach which is the construction of a new natural-gas fired peaking plant. However, what most state regulators are now demanding is a very specific decom-position of the ways in which DR represents a cheaper alternative. There are many approaches toward making this argument, including the facts that capital costs for DR capacity are generally significantly lower than the cost of building a new gas-fired plant, or that DR capacity can be dispatched more quickly than a peaking power plant. Adding to these arguments are the operational benefits that DR can provide over traditional supply-side options, and more specifically how some technologies for conservation voltage reduction (CVR) and volt/VAR optimization (VVO) are being used to enable DR, achieve those operational benefits, and also contribute to the calculation of the "avoided costs" (the value of a power plant that is not built). The technologies themselves are not new—but the difference is the extent to which more utilities will be inclined to pursue them if the same decoupling principles already described are applied to investments in voltage-optimizing strategies.

Both CVR and VVO can be used to lower overall voltage and help shed load during peak times, thus making them important components of an overall DR program. CVR is accomplished by reducing the distribution voltage at the substation, as con-trolled by the utility. For electric consumers, who may not even be aware of the reduction if it is done automatically, reducing the voltage by a fractional amount also creates a reduction in energy consumption, thereby reducing their energy costs without any effort or need on the customer's part. This also has the effect of reducing distribution line losses for the utility. The objective of CVR is to reduce in the context of DR is to reduce consumption by operating toward the lower end of acceptable ANSI voltage ranges.

VVO is an advanced application that runs at a control center for distribution systems or in substation automation systems. It requires coordinated operations with reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation with sensors, controls, and communications systems. Combined with two-way communication infrastructure, a VVO application seeks to minimize power loss or MW demand while maintaining acceptable voltage profiles on the distribution feeders.

So, how do these smart distribution technologies enable DR and what do CVR and VVO specifically have to do with helping utilities to meet their DR objectives? Rather than ask customers to use less energy at peak times, these technologies reduce usage, also during peak times, with automated processes that require very little involvement from the end-use customer. Once the peak is past, they pump the voltage back up to previous levels, thereby protecting their revenues. Consequently, as utilities are building their business case for DR before their state PUC, many are accentuating the development of grid optimization techniques such as CVR and VVO to support a broader case for pursuing DR.

MISSOURI: BEST PRACTICES IN DR COST RECOVERY?

Within the last couple of years, one state has offered what may arguably become a "best practice" template for cost recovery of EE/DR programs. That state is Missouri and it warrants examination in this white paper due to what are precedent-setting aspects of its recent legislation and accompanying regulatory stipulations. Making this example even more significant is the fact that has Missouri has ranked 44th out of the 50 states for its EE policies and programs (according to the American Council for an Energy-Efficiency Economy), a less than desirable position that will surely be enhanced by new programs scheduled to launch or expand in 2013. While the policymaking that will be discussed here was to create EE programs, the regulatory approach offers a potentially applicable blueprint for DR cost recovery as well.

The origins for the Missouri model extend back to 2009, when the state adopted SB 376, the Missouri Energy Efficiency Investment Act (MEEIA). MEEIA requires Missouri's IOUs—Ameren, Kansas City Power & Light, and Empire Electric Co.—to pursue cost-effective EE opportunities but also enables them to earn the same return on EE investments that it does when it builds a new power plant. Based on accounts from those directly involved with the legislation, MEEIA was built upon a recognition of the very real challenges faced by utilities when promoting EE programs and was specifically designed to remove the throughput disincentive associated with EE. But MEEIA goes even further, by including provisions that propose financial incentives for utilities and mechanisms to enable utilities to recoup lost revenue. Also, utilities can recover their demand-side management costs through rate riders so they will not have to wait until a general rate case to recoup their expanses.

The MEEIA legislation and the subsequent regulatory agreements that it has spawned represent the most ambitious EE plan ever proposed in the "Show Me State," including what will ultimately be a significant expansion of utility EE offerings in the state of Missouri, as historically there has been only limited utility spending and, consequently, limited EE programs for utility customers throughout the state. In fact, MEEIA was approved in an environment in which the state's utilities, particularly Ameren, had made claims that they would need to drastically scale back any EE spending if existing and future program expenditures—and lost energy sales that resulted—were not reimbursed.

The MEEIA legislation is also significant because it clearly spells out guidelines for utility cost recovery, including the fact that it: 1) creates a state policy in which DSM investments are treated equally to traditional investments in supply and delivery infrastructure investments; 2) allows for timely recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs; and 3) instructs the Missouri PSC to ensure that financial incentives to encourage utilities to pursue EE are created. With regard to cost recovery specifically, MEEIA has created the groundwork for the state's utilities to recovery direct program costs, losses associated with reduced sales that result from the programs, and any supported costs that demonstrate an impact on shareholder value that programs create in comparison to supply-side alternatives.

In January 2012, Ameren Missouri filed a three-year EE plan that calls for about $145 million in EE investments in the 2013 through 215 time period. Ameren has estimated that the $145 million endeavor, which includes seven residential and four commercial EE programs, will save an estimated 800,000 megawatt-hours by 2015 — the equivalent of the energy consumed by 60,000 homes over the same period. Those savings equal approximately $500 million in fuel not burned and power plants and transmission lines not constructed — benefits to be shared by Ameren and its customers. The Missouri PSC approved the plan in August 2012, and as of this writing only Ameren Missouri has obtained approval from the Missouri PSC for its plan to comply with MEEIA and implement EE programs consistent with the law's intent. It is within the agreement reached between Ameren Missouri and the Missouri PSC that some unique and relevant cost-recovery stipulations that are applicable to our discussion of both removing disincentive and creating incentives for DR.

Beginning in January 2013, Ameren expects to begin investing the $145 million associated with its 11 EE programs. The PSC order also allows for Ameren Missouri to collect, over the next three years, its program costs and 90 percent of its projected lost revenue from customers starting on January 2, 2013. These costs will be collected through a tracker and recovered through base rates contemporaneously with when the expenditures are made, through an increase in customer charges for the residential class. The remaining 10 percent of projected lost revenue is expected to be recovered as part of future rate proceedings.

Further, the order allows Ameren to earn an incentive amount, similar to the earnings on a supply-side investment, based upon kWh savings actually achieved. Specifically, the order provides for an incentive award that would allow Ameren Missouri to earn revenues of approximately $19 million if 100 percent of its EE goals are achieved during the three-year period, with the potential to earn more if energy savings exceeds those goals. Ameren's recovery of incentive award from customers, if its EE program goals are achieved, would begin after the three-year EE plan is complete and upon the completion of an electric service rate case (or potentially with the future adoption of a rider mechanism).

In a comparison with other state regulatory rulemaking related to EE program approval, the Missouri legislation and accompanying PSC order with Ameren Missouri are quite unique for several reasons, which taken together makes this regulatory approach quite significant. First, it ensures that supply-side resources will be valued equally with demand-side resources. Second, it allows for full recovery of the direct program costs, including administration (including evaluation), implementation, and rebates to program participants. Third, it addresses the throughput disincentive by removing the traditional regulatory approach that penalizes utilities for reduced sales that are created by the pursuit of EE/DR. And, fourth, it creates real incentives for the utility to generate additional revenue (and increased shareholder value) by the pursuit of EE.

CONCLUSION: RECOMMENDATIONS FOR A DR REGULATORY STRATEGY

Hopefully this white paper has served its purpose to introduce what are the major regulatory policies and challenges facing utilities that are pursuing DR program development. Further, I hope that by sharing the specific approaches toward decoupling and performance-based incentives that are offered in the Missouri legislation on EE have provided some insights into "best practices" for other state PUCs to examine. In conclusion, there are a number of regulatory strategies that I would suggest every utility pursuing DR consider as they navigate through the unique requirements of their own state PUC jurisdiction:

- Seek to get any disincentive associated with DR removed from the state legislative and regulatory policies. The most common approach to this is to decouple revenues and profits from the amount of electricity sold.
- Seek to have a decoupling mechanism established by your state PUC, if one does not presently exist.
- When considering the investment costs for DR, be sure to include the "avoided costs" of measuring those traditional supply-side investments and other generating capacity that will not be built as a result of the load reduction created by the DR programs.
- Work with your state PUC to ensure that DR (and other EE programs) receive equal treatment within the context of long-term integrated resource plans.
- Encourage your state PUC to allow utilities to earn a portion of the benefits associated with the DR program under a "net benefits sharing" mechanism.
- Along with full-cost recovery, seek to negotiate a performance-based approach for DR with your state PUC, which would include additional bonuses paid to the utility for meeting established targets for performance that are set for the DR program.

Option	**Definition**
Time of Use (TOU)	TOU tariffs are DR programs that segment each billing month into smaller hourly windows each with a separate pricing level related to production costs. Participants are provided price signals to reduce load during higher cost hours. The simplest form of a TOU tariff segments a day into two production cost segments (usually referred to as on-peak and off-peak hours). Further segmentation may include seasonal rates. Eligible customers may be residential, commercial, or industrial users. Participation may be mandatory or voluntary depending on the jurisdiction. Special meters are installed to measure consumption during peak, off-peak, and in some cases, intermediate hours. Rates vary with time of day, day-of-week (since weekends are generally considered off-peak), and season of year (since winter weekdays may be considered off-peak or intermediate hours). Rates are fixed for each period so the customer knows well in advance what the prices will be.
Critical Peak Pricing (CPP)	CPP is a relatively new variant of TOU tariffs that are often designed with two standard TOU periods (on-peak hours and off-peak hours) and a third optional critical peak period. Typically, the two standard TOU periods have specific time frames and prices. The third critical peak TOU period is a floating time frame (an event) which may or may not be in effect on any given day. Advance notification by an LSE's intention to call a CPP event is typically given (up to 24 hours). When the LSE initiates a CPP event, customers receive signals indicating the expected energy prices for the next day. Customers on CPP tariffs receive discounted on-peak and off-peak pricing as tariff incentives creating the opportunity for customers to reduce their energy costs.

Real Time Pricing (RTP)	RTP is typically an hourly market based pricing DR program without specific demand response events called by LSEs. The basic tenet of RTP is that price will determine usage and that the price elasticity within the market will drive customer behavior to reduce load. Prices paid for energy consumed are typically established and made available to customers a day ahead (day ahead pricing) or an hour ahead (hour ahead pricing) permitting customers the opportunity to vary demand and energy use in response to price. Participants are assigned a baseline load shape (sometimes known as a Customer Baseline or CBL). If the customer uses more energy in any hour than their CBL for that hour, then the customer is charged for energy at that hour's market price. The converse is also true. If the customer uses less energy in that hour the LSE will credit the customer for energy not used. RTP is primarily used for commercial and industrial facilities with the ability to reduce or shift loads.
Peak Time Rebate (PTR)	PTR programs offer rebates to customers who use less electricity during critical peak events. As with CPP, if such events are planned then advanced notice can be provided. However, PTR is different than CPP and RTP rates in that rather than charging a higher price during critical events, customers are provided a rebate for reductions in consumption. In addition, some events may occur on an emergency basis, with customer notification given shortly before, or at the initiation of the event. PTR customers may remain on a traditional flat rate or TOU tariff. During a critical event, customer demand must be compared to baseline usage to determine the amount of hourly kW reduction.
Direct Load Control (DLC)	DLC programs involve remote control of appliances such as thermostats, air conditioners, or water heaters. DLC programs are designed to reduce load during extreme events (e.g. high production costs, system reliability, etc.). Customer end uses are directly controlled by the LSE and are shut down or moved to a lower consumption level during events such as an operating reserve shortage. Participants receive substantial credits for decreasing (shedding) load when an event is initiated by the LSE. Some DLC programs provide the LSE with direct control over shedding customer loads (i.e. air conditioning cycling or setback programs). Other programs allow the participant to choose how they will shed load (i.e. interruptible or load curtailment programs). Penalties are usually assessed for nonperformance. DLC programs are primarily marketed to residential and small commercial facilities with equipment, such as air conditioners, that may be "cycled" (turned off) for limited periods of time.
Interruptible / Curtailable Tariff	Under interruptible / curtailable tariffs, customers agree to reduce consumption to a pre-specified level, or by a pre-specified amount, during system reliability events in return for an incentive payment of some form. The programs are generally only available for medium and large commercial and industrial customers, which are more able to shed all or major portions of their load. Interruptible/curtailable customers receive discounted rates or credits

	when they curtail their consumption when directed by their LSE.
Capacity Bidding/ Demand Bidding	Demand bidding/buyback programs allow customers to bid load reductions into utility or ISO/RTO markets. If their bids are accepted, customers are obligated to curtail load.