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Market and Policy Barriers for Demand Response Providing Ancillary Services in U.S. Markets

Peter Cappers, Jason MacDonald, Charles Goldman

Environmental Energy Technologies Division

March 2013

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Market and Policy Barriers for Demand Response Providing Ancillary Services in U.S. Electricity Markets

Prepared for the
Office of Energy Efficiency and Renewable Energy and the Office of Electricity Delivery and Energy Reliability
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Foreword

This report is one of a series stemming from the U.S. Department of Energy (DOE) Demand Response and Energy Storage Integration Study. This study is a multi-National Laboratory effort to assess the potential value of demand response and energy storage to electricity systems with different penetration levels of variable renewable resources and to improve our understanding of associated markets and institutions. This study was originated, sponsored, and managed jointly by the Office of Energy Efficiency and Renewable Energy and the Office of Electricity Delivery and Energy Reliability.

Grid modernization and technological advances are enabling resources, such as demand response and energy storage, to support a wider array of electric power system operations. Historically, thermal generators and hydropower in combination with transmission and distribution assets have been adequate to serve customer loads reliably and with sufficient power quality, even as variable renewable generation like wind and solar power become a larger part of the national energy supply. While demand response and energy storage can serve as alternatives or complements to traditional power system assets in some applications, their values are not entirely clear. This study seeks to address the extent to which demand response and energy storage can provide cost-effective benefits to the grid and to highlight institutions and market rules that facilitate their use.

The project was initiated and informed by the results of two DOE workshops; one on energy storage and the other on demand response. The workshops were attended by members of the electric power industry, researchers, and policy makers; and the study design and goals reflect their contributions to the collective thinking of the project team. Additional information and the full series of reports can be found at www.eere.energy.gov/analysis/.

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List of Figures and Tables

Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
ARC	Aggregator of Retail Customers
AS	Ancillary Service
BA	Balancing Authority
CAISO	California Independent System Operator
DLC	Direct Load Control
DR	Demand Response
ERCOT	Electricity Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
I/C	Interruptible and Curtailable
ILR	Interruptible Load for Reliability
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
IRC	ISO/RTO Council
IRP	Integrated Resource Planning
IOU	Investor-Owned Utility
M$/yr	Million dollars per year
MCP	Market Clearing Price
MISO	Midwest Independent System Operator
MW-h	Megawatt per hour
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NPCC	Northeast Power Coordinating Council
PJM	PJM Interconnection, LLC
PSCo	Public Service of Colorado
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
U.S.	United States

Executive Summary

Introduction

The electricity grid requires various types of bulk power system services to maintain power quality, reliability, and security. Increasing penetration of renewable energy generation in U.S. electricity markets, driven primarily by state-level renewable portfolio standard (RPS) policies (Wiser et al. 2010), means that system operators will need to manage the variable and uncertain nature of many of these renewable resources to continue to meet their charter. This in turn is likely to require operational changes and procurement of greater quantities of various bulk power system services (NERC 2009). For example, system operators will likely need to procure, among other things, more ancillary services to fully accommodate the sizable addition of these variable generation resources (see Table ES-1).[i] Independent System Operators or Regional Transmission Organizations (ISO/RTO) in the U.S. typically procure various ancillary services via a centralized auction such that those who are committed to provide the services are paid a market-clearing price that fluctuates over time reflecting exigent system conditions, supply availability, and other factors. In jurisdictions without organized wholesale markets (hereafter referred to as non-ISO/RTO market environments), the Balancing Authority (BA) typically has a cost-based tariff, which is updated annually, that stipulates charges to transmission customers who do not self-supply or procure through a third-party sufficient capacity to meet their AS requirement.

Table ES-1: Bulk power system operations affected by large-scale deployment of variable generation

	Time Scale				
Bulk Power System Operations	**Procurement or Schedule**	**Control Signal**	**Advance Notice of Deployment**	**Duration of Response**	**Frequency of Response**
Spinning Reserves (Contingency)	Days to hours ahead	<1 min	~1 min	~30 min	~20-200 times per year
Supplemental Reserves (Contingency)	Days to hours ahead	<10 min	~10-30 min	~Multiple hours	~20-200 times per year
Regulation (Normal Operation)	Days to hours ahead	~1 min to 10 min	None	< 10-min in one direction	Continuous

Adapted from Cappers et al. (2012)

Traditionally, ancillary services have been provided exclusively by generators. But over the past decade, alternative resources like demand response (DR) have become increasingly capable of providing such bulk power system services. Conceptual studies have argued that DR resources are well-suited to provide AS to the grid due in part to their fast response, distributed nature and the statistical reliability of large numbers of smaller resources (Kirby 2007; Callaway 2009; NERC 2009). These resources may be able to provide bulk power system services like AS at a lower cost and with a smaller carbon footprint than new conventional generation resources (Wellinghoff 2009), and can potentially be brought to market quicker as they don’t have to go through lengthy permitting, siting and regulatory approval processes. Additionally, limited field

[i] In addition to ancillary services, many renewable integration studies (e.g., GE Energy 2008; Makarov et al. 2009; NERC 2009) have identified a need for greater ramping capability to track large but relatively slow changes in electricity production from variable renewable generation resource. Since this product has not yet been defined by NERC or any of the balancing authorities, we chose to focus on the bulk power system services that are currently defined.

tests of DR resources providing various forms of AS (Kirby and Kueck 2003; Todd et al. 2008; Kiliccote et al. 2009; Eto et al. 2012) have verified its technical capability.

However, while DR resources can technically provide these services, they may not do so until enabled by the entities and organizations that directly and indirectly affect a customer's interaction with the bulk power system. Federal regulators and reliability organizations create a framework for rules of operation through tariffs and other documents that affect the bulk power system of the various balancing authorities in America. However, federal regulatory influence to create opportunities for DR to more effectively participate as a resource is much greater in ISO/RTOs than for non-ISO/RTO BAs. Even if a balancing authority creates such opportunities, state regulators and legislators define the conditions under which electric utilities and aggregators of retail customers (ARC) can engage with customers.

As such, identification of barriers to DR resources' participation as an ancillary service provider and the entities responsible for addressing them is important at both the wholesale and retail level. Cappers, Mills et al. (2012), FERC (2009), and Kirby (2006) all identified various barriers limiting demand response resources from providing different bulk power system services (including ancillary services). FERC (2009) provided a high level summary of these issues and a more detailed assessment of barriers in California based on interviews. Kirby (2006) focused more on the technical requirements that DR resources must meet to provide ancillary services, while Cappers et al. (2012) identified the extent to which various DR opportunities could provide different bulk power system services based on current rate and program designs.

Objective and Scope

In this study, we attempt to provide a comprehensive examination of various market and policy barriers to demand response providing ancillary services in both ISO/RTO and non-ISO/RTO regions, especially at the program provider level. It is useful to classify barriers in order to create a holistic understanding and identify parties that could be responsible for their removal. This study develops a typology of barriers focusing on smaller customers that must rely on a program provider (i.e., electric investor owned utility or IOU, ARC) to create an aggregated DR resource in order to bring ancillary services to the balancing authority.[ii] The barriers were identified through examinations of regulatory structures, market environments, and product offerings; and discussions with industry stakeholders and regulators. In order to help illustrate the differences in barriers among various wholesale market designs and their constituent retail environments, four regions were chosen to use as case studies: Colorado, Texas, Wisconsin, and New Jersey. We highlight the experience in each area as it relates to the identified barriers.

[ii] Large customers (e.g., aluminum smelting) in most ISO/RTO environments can and often times do currently participate directly in the market as an ancillary service provider. As such, the barriers they faced bringing their capabilities to the bulk power system are somewhat different than those of smaller customers (e.g., retail office buildings) who must go through a program provider (i.e., IOU, ARC). For example, large customers usually have the requisite interval metering already installed, can provide load reductions that meet minimum size requirements, and can more readily afford to invest in the necessary telemetry requirements. As such, we are focusing in this study on the barriers standing in the way of BAs gaining access to smaller DR resources, as this is the group of customers that is still largely untapped. Many of the barriers listed here do still apply to larger electricity customers willing and able to go directly to the BA, but specifying where and explaining why this is or is not the case is beyond the scope of this paper.

Findings

Our review of the literature provided a useful starting point for our development of a typology. Since many of the specific barriers we identified could apply to several of the categories others' had constructed, we developed an alternative approach to characterizing barriers based on a logical progression from bulk power system service definitions to physical and financial requirements for DR resources to provide ancillary services through a program provider that better captures this interrelatedness (see Table ES-2).[iii] Barriers associated with *Bulk Power System Service Definitions* relate to the way in which reliability organizations and BAs chose to define a service that includes/excludes certain classes of resources explicitly. These barriers must be dealt with first in order for a DR resource to even be able to provide these types of bulk power system services. Once a DR resource is eligible to provide such services, the rules developed by BAs that define the *Attributes of Performance* (e.g., minimum resource size) and the required *Enabling Infrastructure Investments* (e.g., automation and control technology, telemetry) for these services can create implicit barriers that may hinder program providers and DR resources from participating effectively in these AS markets. DR program providers and the participating customers must assess and decide whether the available revenues from participating in various AS markets are sufficient (*Revenue Availability*) and can be captured with enough certainty (*Revenue Capture*) to meet simple payback periods for customers or return on investment hurdle rates of IOUs or ARCs for all fixed and variable enabling infrastructure investment costs. The regulatory compact between utility and regulator, along with other statutes and decisions by state policymakers, may also create barriers that *Program Providers* must overcome in order to pursue DR resources more vigorously as an ancillary service provider.

Table ES-2: Applicable entities and organizations responsible and affected by barriers

	Reliability Council	BA	IOU	ARC	Utility Regulator	End-use Customer
Bulk Power System Service Definitions	✷	✷,●	●	●		
Attributes of Performance		✷	●	●		●
Enabling Infrastructure Investments		✷	●	●		●
Revenue Availability		✷	●	●		
Revenue Capture		✷	●	●		●
Program Providers		✷	●	●	✷	●

✷ - Entity/Organization responsible for creating the barrier
● - Entity/Organization affected by the barrier

[iii] A barrier type not explicitly mentioned in the typology presented in Table ES- 2 has to do with procedural issues. Procedural barriers generally relate to the process by which other barriers are removed. As such, these are not direct barriers to entry but rather introduce additional transaction costs, both in time and financial resources, in implementing solutions to any identified barriers. For instance, ISO/RTOs that are attempting to change their product definitions must: initiate internal and external stakeholder processes that require among other things overcoming preconceptions about capabilities of particular resources; seek approval from regulators before any changes may be made to operating practices; and then contend with both financial and human capital resource constraints that can significantly slow market changes. A similar issue is found with retail electric utilities who must address certain barriers through internal and external stakeholder processes that include seeking regulatory approval for tariff changes, which likewise can be a time-consuming process. These less direct barriers permeate the entire structure of the typology presented in Table ES- 2.

One of the most effective ways to remove these barriers is to alter the requirements imposed on DR resources wishing to provide AS (see Table ES-3). By acknowledging that demand response is fundamentally different than a generator, many ISO/RTOs are currently finding ways to alter the requirements to provide these services such that the quality of the service they are procuring is maintained but the pool of resources that can provide it is expanded. In contrast, most non-ISO/RTO BAs do not appear to be as far along in their attempts to better integrate non-traditional resources as ancillary service providers. Additionally, with advancements in technology through research and development efforts and with increased market adoption, the cost of automation and control technology and other forms of enabling infrastructure investments should continue to drop making participation as an AS provider more cost effective. Increases in benefits, through market rule changes (e.g., scarcity pricing, reserve demand curves) can likewise contribute to an increase in the cost effective procurement of AS from demand response. Finally, altering the process by which program providers do business (e.g., changes in the utility's business model) should help further facilitate increased interest in pursuing DR resources as a viable AS provider.

Table ES-3: Actions required to overcome barriers

	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Bulk Power System Service Definitions	◆				
Attributes of Performance		◆			
Enabling Infrastructure Investments		◆		☐	
Revenue Availability					◆
Revenue Capture		◆			
Program Providers			◆	☐	☐

◆ - Primary action to overcome barrier
☐ - Secondary action to overcome barrier

The four regions focused on in this study illustrate these various barriers and ways in which the regions have or are attempting to address them.

Colorado has a vertically integrated retail utility environment that operates within a non-ISO/RTO BA footprint. This results in little to no opportunities for ARCs directly soliciting customers to bring DR resources forward to provide AS unless there is someone on the other end to buy their services. The BA doesn't provide such a "marketplace", so the ARCs must develop relationships with the utilities in the BA's jurisdiction in order to play some sort of role. The investor-owned utilities, as the sole provider of electricity service to customers, have only modest profit motives to pursue non-generation resources, like DR, as an AS provider. Colorado utilities and state regulators have not placed expansion of DR programs to provide ancillary services as a high priority given the excess capacity situation currently experienced by the state's utilities. If the capacity situation tightens and/or the distribution system requires attention due to increased penetration of distributed variable renewable resources, which may occur later this decade due to the state's RPS requirements, state regulators as well as the utilities could be more inclined to consider such new DR opportunities.

Texas, with its open retail market and integrated wholesale market, appears to have conditions that are highly conducive for DR resources to readily provide ancillary services. ERCOT has indeed attracted a substantial amount of demand response to its markets, enrolling ~2,400MW of capacity to provide spinning reserves (Patterson 2011). The vast majority of this is provided by industrial facilities who have peak demands of 10 MW or more and utilize under-frequency relays that were installed through utility-sponsored instantaneous interruptible tariffs years prior to the advent of the organized wholesale market (Zarnikau 2010). While ERCOT has been very successful at operating with sizable amounts of ancillary services provided primarily by these large customers (e.g., DR resources can and often do provide up to 50% of the spinning reserve requirement), relatively few new DR resources have been brought to market that aggregate smaller customers. Conversations with program providers and regulatory staffers illustrate the challenges that the open retail market creates when trying to attract these smaller DR resources. The distribution utilities, who no longer have supply obligations to customers, have little profit motive to pursue such programs, which means regulators must get involved to either create the business case or mandate that programs be offered. Competitive retail electricity suppliers do not yet readily see a value proposition in offering the requisite types of enabling technology as an additional service due in part to short customer contract lengths which do not exceed the return on investment hurdle rates on the equipment. The current wholesale “energy-only” market design does not provide a reservation payment that guarantees a longer term (e.g., quarterly, semi-annual, or annual) revenue stream compared to other ISO/RTOs that administer capacity markets. This adds risk into the decision to invest in enabling infrastructure at customer premises. Reserve margins that exceeded ERCOT requirements by 2-4 percentage points coupled with major changes at ERCOT to a nodal market over the last several years resulted in time and effort not being directed towards creating greater opportunities for DR resources to participate in the market. Although with more recent reserve shortages, ERCOT and the Texas Public Utility Commission are jointly working through the stakeholder process to resolve these issues and improve the environment for DR in general (see Public Utility Commission of Texas Project No. 40000 for more details).

New Jersey is in a similar situation as Texas but for somewhat different reasons. The incumbent utilities’ business model creates little incentive for them to pursue new DR resource in any fashion, let alone as an ancillary service. New Jersey allows retail competition and utilities currently provide electric commodity and ancillary services as a bundled product for default service customers through a multi-year contracting (i.e., auction) process. The costs of this bundled product are completely passed through to these customers, which provides little incentive for the utility to pursue lower cost options to provide these services *outside of the auction process* nor any ability to do so within the auction process since the products are bundled. So even though PJM is on the forefront of creating and expanding opportunities for DR resources to provide various forms of ancillary services, it is only ARCs or competitive retail providers going directly to the market or through bilateral contracts with third-party suppliers[iv] who are likely to bring resources to market, absent state regulatory engagement.[v]

[iv] Third-party electricity suppliers provide capacity, energy, and ancillary services as a portfolio to competitive electricity suppliers or the incumbent utility for default service. The goal of third-party suppliers is to provide the product at least-cost, which may entail pursuing DR as a resource within the portfolio.
[v] The New Jersey Board of Public Utilities (NJBPU) in 2008 did get involved by ordering the utilities to augment DR program payments for new resources participating in PJM’s 2009 Interruptible Load for Reliability (ILR)

Wisconsin, with its regulated retail environment and restriction on ARCs providing DR programs, faces both regulatory and utility business model barriers that limit their utilities' interest in pursuing DR resources as an ancillary service provider. Electric utilities in this state are vertically integrated. Since they rely on their own generation assets to serve customers' needs, any reductions in non-fuel operating expenses from more efficiently operating this fleet of resources can be captured by the utility but only until new rates are set which reflect these now lower costs. Although these types of DR programs also create an opportunity for the state's utilities to convert reserved generation capacity into energy which can be sold off-system, state regulators do not allow the utility to retain any of these profits but instead require the utility to turn them over to ratepayers. Furthermore, the electric utilities profit from investing in capital assets, like new generating stations, which is often not true for DR investments. As such, Wisconsin utilities have only modest financial incentives to pursue DR resources in general, while state regulators have restricted ARCs from doing business in the state. Should state regulators choose to alter the utility's business model making the pursuit of DR resources as an AS provider more lucrative, the utility must alter its existing tariff to expand the conditions under which current and future DR resources can be dispatched. Regulators could also choose to lift their moratorium on ARCs to further facilitate access to DR resources that can provide ancillary services. However, at this time, based on our interviews, the Commission does not appear inclined to look into these issues in the near future.

These four regions included as case studies in this report are likely representative of the experience in similar wholesale and retail market environments across the country. Our assessment of the barriers to smaller DR resources providing ancillary services illustrates that the issues span nearly all entities and organizations in the chain that connects wholesale markets to retail customers. Fundamentally, in a highly regulated system, incentives must be aligned among the balancing authority, utilities, and program providers in order for DR resources to reach the system operator, where AS is procured. Most of these entities have little to no incentive to address these barriers on their own, even if society as a whole could greatly benefit from the effort. Thus, many different but disparate parties will need to work together for the common good in order for smaller DR resources to reach their full potential as a provider of ancillary services.

program through a series of one-year pilots with a goal of fostering cooperation with ARCs (NJBPU 2008). Two years later, the NJBPU stopped all utility pilot programs due to a lack of funding; leaving ARCs to continue enrolling customers directly in PJM programs without any augmented payment (NJBPU 2010).

1. Introduction

The electricity grid requires various types of bulk power system services to maintain power quality, reliability, and security. Increasing penetration of renewable energy generation in U.S. electricity markets, driven primarily by state-level renewable portfolio standard (RPS) policies (Wiser et al. 2010), means that system operators will need to manage the variable and uncertain nature of many of these renewable resources to continue to meet its charter. This in turn is likely to require operational changes and procurement of greater quantities of various bulk power system services (NERC 2009). For example, system operators will likely need to procure, among other things, more ancillary services to fully accommodate the sizable addition of these variable generation resources (see Table 1).[1] The type and level of additional bulk power system services needed depend on a variety of factors from location to adoption of different technologies. In California, for example, an increase in the amount of regulation capacity is expected to largely accommodate rapid changes in solar power plant output (Makarov et al. 2009; Helman 2010), while in Texas, studies suggest that the need for spinning reserves (called responsive reserves in ERCOT) is growing to accommodate large unexpected wind ramps (GE Energy 2008).

Currently these various forms of ancillary services (e.g., reserves and regulation) are products which Balancing Authorities (BA) are responsible for procurring. Where the BA runs an organized wholesale market in the U.S., commonly referred to as an Independent System Operator or Regional Transmission Organization (ISO/RTO), ancillary services are typically procured via a centralized auction such that those who are committed to provide the services are paid a market-clearing price. In jurisdictions that have no organized wholesale markets, the BA typically has a cost-based tariff that stipulates charges to transmission customers who do not self-supply or procure through a third-party sufficient capacity to meet their AS requirement (hereafter referred to as non-ISO/RTO BA environments).

Table 1: Bulk power system operations affected by large-scale deployment of variable generation

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Adapted from Cappers, Mills et al. (2012)

[1] In addition to ancillary services, many renewable integration studies (e.g., GE Energy 2008; Makarov et al. 2009; NERC 2009) have identified a need for greater ramping capability to track large but relatively slow changes in electricity production from variable renewable generation resource. Since this product has not yet been defined by NERC or any of the balancing authorities, we chose to focus on the bulk power system services that are currently defined.

Traditionally, ancillary services have been provided exclusively by generators. However, over the past two decades, alternative resources like demand response (DR) have become increasingly capable of providing such bulk power system services. Conceptual studies have argued that certain forms of DR resources are well-suited to provide AS to the grid due in part to their fast response, distributed nature and the statistical reliability of large numbers of smaller resources (e.g., Kirby 2007; Callaway 2009; NERC 2009). These resources may be able to provide bulk power system services like AS at a lower cost and with a smaller carbon footprint than new conventional generation resources (Wellinghoff 2009), and can potentially be brought to market quicker as they do not have to go through lengthy permitting, siting and regulatory approval processes. Additionally, limited field tests of DR resources that provided various forms of AS (Kirby and Kueck 2003; Todd et al. 2008; Kiliccote et al. 2009; Eto et al. 2012) have verified their technical capability.

However, while DR resources can technically provide these services, they may not do so until enabled by the entities and organizations that directly and indirectly affect a customer's interaction with the bulk power system. Federal regulators and reliability organizations create a framework for rules of operation through tariffs and other documents that affect the bulk power system of the various balancing authorities in America. However, federal regulatory influence to create opportunities for DR to more effectively participate as a resource is much greater in ISO/RTOs than for non-ISO/RTO BAs. Even if a balancing authority creates such opportunities, state regulators and legislators define the conditions under which electric utilities and aggregators of retail customers (ARC) can engage with customers.

As such, identification of barriers to DR resources' participation as an ancillary service provider and the entities responsible for addressing them is important at both the wholesale and retail level. For example, many of the current BA ancillary services procurement rules and qualification policies were initially designed under a "generator-only" paradigm. As such, the playing field for provision of such ancillary services has not been level, generally favoring traditional generation resources for which the services were originally designed. The Federal Energy Regulatory Commission (FERC) issued several recent decisions that attempt to address and rectify the situation (FERC 2008, 2011a) in ISO/RTO jurisdictions and mandate that fast acting resources be compensated for the additional security that their flexibility brings the grid (FERC 2011b).[2] Furthermore, utility demand response programs, which have historically been the mainstay for customer DR opportunities, have not traditionally provided ancillary services. There are, however, non-utility DR program providers (i.e., ARCs) whose business model is predicated on enabling and subscribing customers to provide these types of services; yet they may be precluded from doing so based on state statutes or regulatory decisions. Therefore, state

[2] FERC's Order 719 (FERC 2008) required ISO/RTOs to eliminate several identified barriers to demand response by amending their market rules as follows: accept bids from DR resources in certain AS markets; allow Aggregators of Retail Customers to fully participate in the market unless prohibited by the relevant regulatory authority; and modify pricing mechanisms during system emergencies and/or operating reserve shortages. FERC's Order 745 (FERC 2011a) sought to further eliminate barriers to demand response by requiring ISO/RTOs to amend their market rules to fully compensate DR at the locational marginal-price for providing energy when certain conditions apply. FERC's Order 755 (FERC 2011b) adopted a two-part compensation method for all resources that provide regulation service by requiring ISO/RTOs to pay all resources that clear the regulation market a: (1) uniform capacity payment; and (2) a performance payment based on the accuracy of response to system control signals.

regulators and legislators have a role to play in creating opportunities for retail entities (electric utilities and ARCs) to see value in altering or expanding their program offerings.

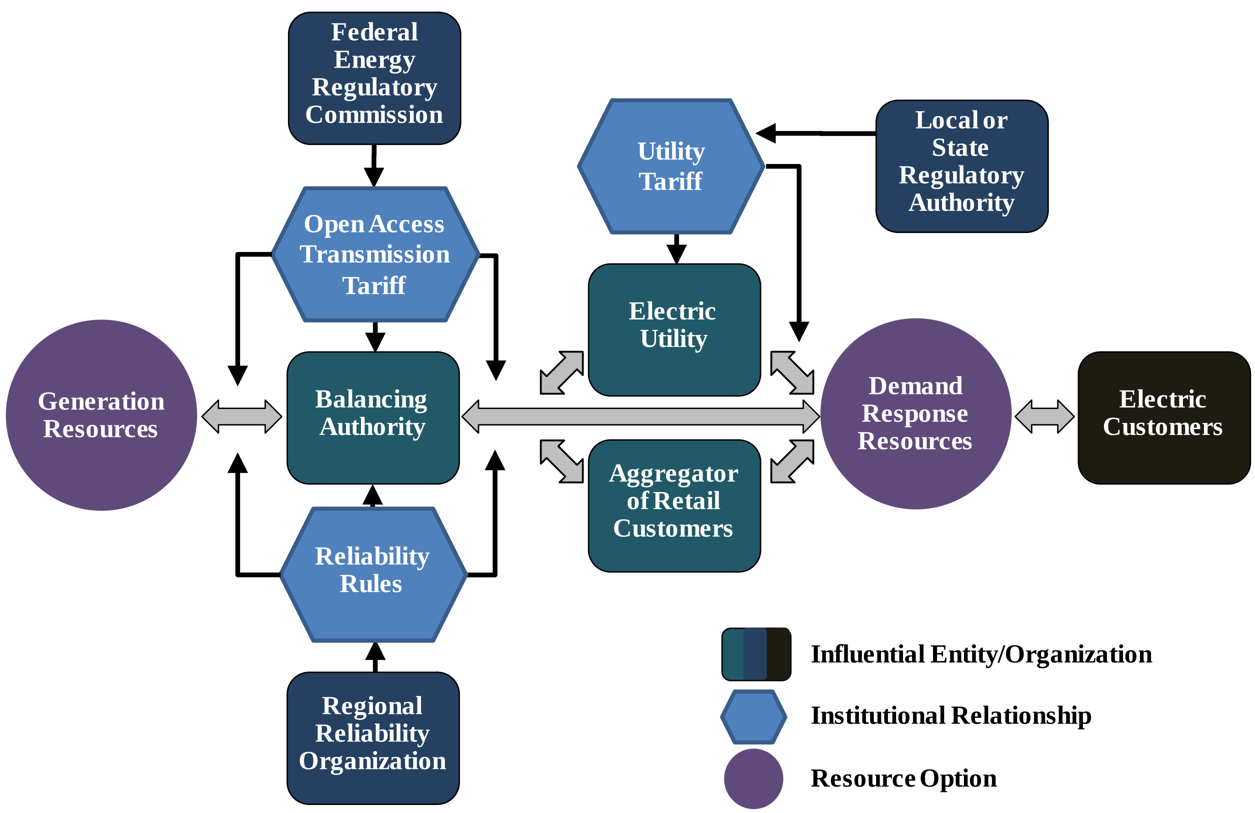
Although some of the barriers hindering DR resources from providing ancillary services have been identified and addressed (e.g., FERC), a comprehensive assessment of these barriers could help the electric industry identify the entities most capable of undertaking the necessary actions to overcome them such that DR resources can reach their full potential. Cappers et al. (2012), FERC (2009), and Kirby (2006) all identified various barriers limiting demand response resources from providing different bulk power system services (including ancillary services). FERC (2009) provided a high level summary of these issues and a more detailed assessment of barriers in California based on interviews. Kirby (2006) focused more on the technical requirements that DR resources must meet to provide ancillary services, while Cappers et al. (2012) identified the extent to which various DR opportunities could provide different bulk power system services based on current rate and program designs.

In this study, we attempt to provide a comprehensive examination of various market and policy barriers to demand response resources associated with smaller customers who must go through a program provider in order to provide ancillary services in either an ISO/RTO or non-ISO/RTO region.[3] This report is organized as follows. We first present a general description of U.S. electricity market environments and include a proposed typology for the assessment of barriers to DR resources providing ancillary services (see sections two and three). That framework is used to organize the subsequent discussion in sections four through nine of individual barriers (e.g., barriers that arise because of bulk power system service definitions, enabling infrastructure barriers, and barriers to participation by certain types of DR program providers). In order to help illustrate the differences among wholesale markets and their constituent retail environments, four states were chosen to use as case studies: Colorado, Texas, Wisconsin, and New Jersey. We highlight the experience in each area as it relates to the identified barriers throughout the paper and then summarize that experience in the conclusions (see section 10).

[3] Large customers (e.g., aluminum smelting) in most ISO/RTO environments can and often times do currently participate directly in the market as an ancillary service provider. As such, the barriers they faced bringing their capabilities to the bulk power system are somewhat different than those of smaller customers (e.g., retail office buildings) who must go through a program provider (i.e., IOU, ARC). For example, large customers usually have the requisite interval metering already installed, can provide load reductions that meet minimum size requirements, and can more readily afford to invest in the necessary telemetry requirements. As such, we are focusing in this study on the barriers standing in the way of BAs gaining access to smaller DR resources, as this is the group of customers that is still largely untapped. Many of the barriers listed here do still apply to larger electricity customers willing and able to go directly to the BA, but specifying where and explaining why this is or is not the case is beyond the scope of this paper.

2. Influential Entities and Organizations in Wholesale/Retail Market Environments

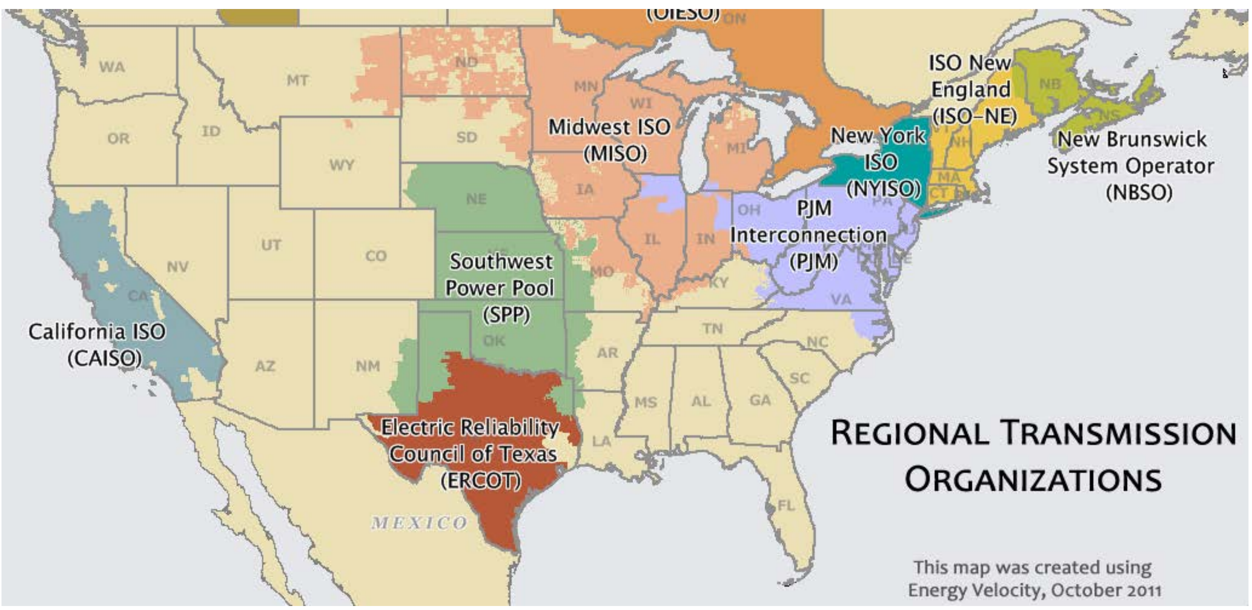
A variety of different entities and organizations directly and indirectly affect an individual customer's ability to provide a bulk power system service to the balancing authority (see Figure 1). Retail entities, specifically electric utilities and aggregators of retail customers, harness the demand response capabilities of electric customers through tariff rates and DR programs that are approved or allowed by the applicable state or local regulatory authority. Although the balancing of supply and demand is managed at the wholesale level by a balancing authority, this entity functions under open access transmission tariffs approved by the Federal Energy Regulatory Commission (FERC) and must operate their system in accordance with rules set by regional reliability organizations. These rules are derived from enforceable standards set by the North American Electric Reliability Corporation (NERC). Thus, the role that DR resources can play in providing ancillary services (or any bulk power system service) is contingent on what opportunities state and local regulators are willing to promote and approve, as well as how customers' response to the DR opportunities can be integrated into the bulk power system both physically (due to reliability rules) and financially (due to tariffs and market rules). The barriers that must be addressed by these various entities and organizations differ depending upon the type of wholesale and retail electricity market environment that exists.



Adapted from Cappers et al. (2012)

Figure 1: Entities and organizations that influence relationships between resources and the bulk power system

There are seven organized wholesale electricity markets in the U.S. operated by BAs known as Independent System Operators or Regional Transmission Organizations (see Figure 2). Each ISO/RTO has its own set of rules that dictate the structure of its various markets for different bulk power system services, but all are based on a basic auction concept that brings multiple buyers and sellers together. These markets provide transparent price signals for all transacted products, including ancillary services, which are not present in BAs solely with bilateral markets (the remainder of the country). ISO/RTOs can be characterized by the types of wholesale markets they run and the way in which they operate. Some ISO/RTOs have a market design that includes a forward capacity market which provides a reservation payment to all resources selected to provide planning reserves (e.g., generators, demand response), while others just have an “energy-only” market design where no such capacity market exists and thus no upfront revenue source is available. In contrast, all ISO/RTOs procure or plan to procure ancillary services and energy in day-ahead forward and/or real-time spot markets. Energy and ancillary service markets are co-optimized in all ISO/RTOs but one to jointly procure the necessary levels of ancillary services and energy at least cost. The remaining ISO/RTO (i.e., SPP) plans to operate AS markets and co-optimize procurement by 2014. ISO/RTOs also differ in the way they determine their required ancillary service capacity to procure. Some ISO/RTOs set a flat amount that must be procured for every hour of the year (e.g., ERCOT); others determine a monthly requirement that varies every hour (e.g., MISO); and still others establish their requirement as a function of the daily forecast of system load (e.g., PJM).



Source: FERC (2012)

Figure 2: Map of ISO/RTO balancing areas in the U.S.

In regions without ISO/RTOs (see Figure 2), the BA runs a day-ahead unit commitment model and in-day dispatch model of resources for energy and ancillary services like their ISO/RTO counterparts; however, these are predominantly based on schedules provided by vertically-integrated utilities and the non-utility generators producing the energy or providing the ancillary services and usually prices are not produced out of these operating platforms. The utilities will generally notify the BA that they have a balanced schedule for all necessary services, which they will have forecasted and subsequently procured from a portfolio of their own fleet of resources, long-term power purchase agreements with other resources, and short-term bilateral contracts with other resources. In contrast to the ISO/RTO markets, any shortfalls in meeting this balance is charged at the transmission tariffs' stipulated value for providing these services based on a FERC-approved cost-of-service analysis. Although power exchanges do enable trading of electric commodities in these regions, these markets are voluntary and simply match one buyer and one seller.

As with wholesale electric markets, there are also significant differences in the structure and design of retail electricity markets in the United States. First and foremost, electric utilities can differ in the way they are owned and governed. Electric cooperatives are generally owned by their members, who also happen to be ratepayers, and governed by a board of directors. Public utilities are owned and generally governed by the municipalities they serve. Private shareholders own investor-owned utilities, which are regulated by either an elected or state-appointed group of utility commissioners. For purposes of this report, we will be focusing exclusively on IOUs when determining the market and policy barriers hindering DR resources from providing ancillary services, as the business model and regulatory issues for municipalities and rural cooperatives can be quite different. Among investor owned utilities, some states allow retail competition where the utility retains monopoly status for the provision of transmission and distribution services but not electric supply service. Customers, therefore, are free to choose their electricity supplier, even though in all of these states, except Texas, utility commissions have required the monopoly transmission and distribution utility to serve as the default electricity supplier. In states that do not allow retail competition, IOUs maintain their monopoly status as the provider of all three services. Electric utilities can also be characterized by their ability to own and operate generation assets. A vertically integrated utility has its own fleet of generation resources that are used to serve the electricity needs of its customers, whereas a distribution utility may have divested or sold some or all of these generation assets at some point in the past. Such distribution utilities must now contract with non-utility electricity suppliers (e.g., private power generators) to procure the necessary energy, capacity and ancillary services to meet its customers' demands through long-term contracts and short-term purchases on the spot market. In addition, some investor-owned utilities, but not all, have the ability to retain some or all of the profit associated with either selling excess power they have produced and/or arbitraging power purchased through long-term forward contracts in the spot electricity market. Lastly, the IOU has, up until about the turn of the millennium, been the sole provider of demand response programs. In some jurisdictions, third party aggregators of retail customers are now able to offer DR programs that compete directly with the utility's offered programs.[4]

In this study, we selected four distinct states to represent the diversity of wholesale and retail environments in the United States: Colorado, New Jersey, Texas, and Wisconsin (see Table 2). Colorado is the lone state in our analysis that is in a non-ISO/RTO BA environment. Electric utilities in Colorado are vertically integrated and do not face retail electricity supply competition. Wisconsin electric utilities are likewise vertically integrated and have no competition for supply

[4] Where wholesale market DR programs exist, utilities and ARCs (where allowed) provide opportunities for customers to subscribe to these ISO/RTO DR programs. For simplicity, we characterize this as the ARC or utility offering DR programs as a "program provider" even though they technically only offer a service to facilitate entry into the ISO/RTOs DR program.

service, but operate within the MISO footprint. Texas and New Jersey both have retail competition, where customers can procure electric supply from any number of different entities within the ERCOT and PJM footprints, respectively. The incumbent electric utilities in New Jersey must act as the default service provider for all customers in their service territory, whereas the incumbent electric utilities in Texas have no such supply obligation.

Table 2: Wholesale and retail difference among case study regions

		Colorado	Texas	Wisconsin	New Jersey
Wholesale	Dominant Balancing Authority	PSCo	ERCOT (ISO)	MISO	PJM (RTO)
	Capacity Market Exists?	N/A	No	Yes*	Yes
	Co-optimized Energy & Ancillary Services?	N/A	Yes	Yes	Yes
	AS Capacity Determination?	Constant, Annually	Constant, Annually	Daily shape, monthly	Based on Forecasted Load
Retail	Allows retail competition?	No	Yes	No	Yes
	Distribution IOU?	No	Yes	No	Yes

* MISO’s capacity market is strictly voluntary and covers capacity obligations only one month ahead.

3. Market and Policy Barrier Typology

When considering the market and policy barriers to provision of ancillary services by demand response resources, it is useful to classify barriers in order to create a holistic understanding and identify parties that could be responsible for their removal. This study develops a typology for barriers based on examinations of regulatory structures, market environments, and product offerings and conversations with industry stakeholders and regulatory staff. Based on our literature review, we identified several sources that identified and characterized a typology of DR resource barriers. For example, FERC (2009) categorized barriers into four groups: regulatory, economic, technological and other. Regulatory barriers are those that are created by entities and organizations that operate, regulate and/or dictate the definitions and requirements imposed on providers of AS. Economic barriers are those that affect the financial willingness of entities and organizations to pursue opportunities to provide AS. Technological barriers to implementation of demand response are those that require a customer and/or program provider to invest in new control, automation, metering, and/or communications equipment. Other barriers simply fall outside of these three categories.

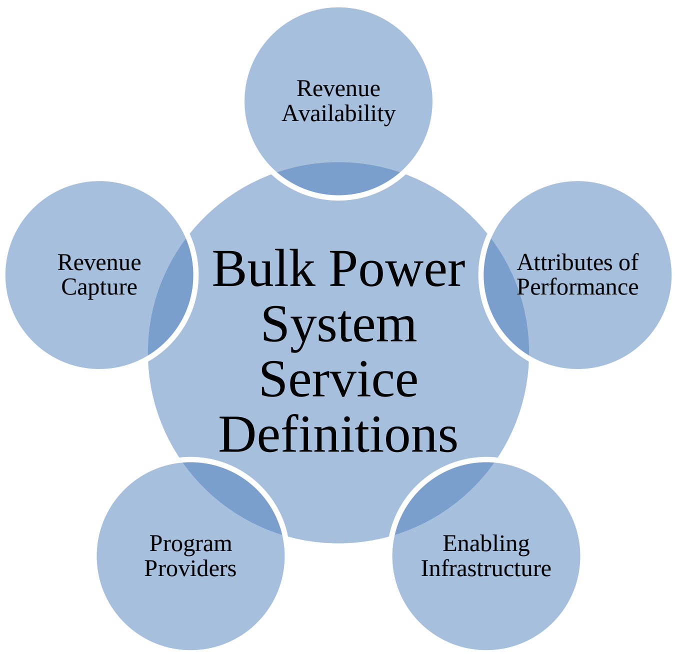


Figure 3: Conceptual framework for a typology of barriers to demand response resources providing ancillary services

Our review of the literature provided a useful starting point for our development of a typology. Since many of the specific barriers we identified could apply to several of the categories others' had constructed, we developed an alternative approach to characterizing barriers that captures their interrelatedness (see Figure 3), from the perspective of DR program providers. Barriers associated with *Bulk Power System Service Definitions* relate to the way in which reliability organizations and the BAs chose to define a service that includes/excludes certain classes of resources explicitly. These barriers must be dealt with first in order for a DR resource to even be able to provide these types of bulk power system services. Once a DR resource is eligible to provide such services, the rules developed by balancing authorities to define the *Attributes of*

Performance (e.g., minimum resource size) and the required *Enabling Infrastructure* (e.g., telemetry requirements) for these services can create implicit barriers that may hinder program providers and DR resources from participating effectively in these AS markets. Such requirements may limit and constrain interest in participation if these requirements are perceived to be too onerous or costly. DR program providers and their participants must assess and decide whether the available revenues from participating in various AS markets are sufficient (*Revenue Availability*) and can be captured with enough certainty (*Revenue Capture*) to meet simple payback periods of customers or return on investment criteria of IOUs and ARCs for all fixed and variable enabling infrastructure investment costs.[5] *Program Providers* must also specifically contend with a host of additional issues (e.g., viability of business model, ability to offer programs) that may limit their interest in pursuing DR resources as an ancillary service provider. Each of these barrier categories is discussed in more detail below and in the appendices.

A final barrier type not explicitly mentioned in the typology presented in Figure 3 has to do with procedural issues. Procedural barriers generally relate to the process by which other barriers are removed. As such, these are not direct barriers to entry but rather introduce additional transaction costs, both in time and financial resources, in implementing solutions to any identified barriers. For instance, ISO/RTOs that are attempting to change their bulk power system service definitions must: initiate internal and external stakeholder processes that require overcoming preconceptions about the capabilities of particular resources; seek approval from federal regulators before any changes may be made to operating practices; and then contend with both financial and human capital resource constraints that can significantly slow market changes. A similar issue is found with retail electric utilities who must address certain barriers through internal and external stakeholder processes that include seeking regulatory approval for tariff changes, which likewise can be a time-consuming process. These more indirect barriers permeate the entire structure of the typology presented in Figure 3.

[5] This barrier is not unique to DR but rather one faced by any new resource seeking to enter a market.

4. Bulk Power System Service Definitions Barriers

Barriers associated with bulk power system service definitions are those that preclude demand response from participating as an ancillary service resource by defining specific resource types eligible to provide a particular product that do not include or effectively exclude demand response. These definitional barriers arise in both North American standards and regional product definitions.

Regional reliability organizations define the bulk system reliability requirements, including ancillary services, for the areas under their jurisdiction. In defining the service, such entities may explicitly identify which type of resource can provide that service. The North American Electricity Reliability Corporation, a reliability standards setting institution, has defined all ancillary services such that demand response is included among the resources that may provide the services (NERC 2010). However, some regional reliability organizations have yet to adopt similar standard language and do not allow provision of some ancillary services from DR resources. As an example, the Western Electricity Coordinating Council, which covers Colorado, does not currently allow DR resources to provide regulation service (WECC 2007); however, all three of the reliability councils covering the ISO/RTOs included in this study (i.e., ERCOT, MISO and PJM) have adopted language similar to NERC's standard.

A balancing authority also has an opportunity to further refine the requirements for the types of resources that can provide its reliability services as well as those for which it has integrated into its market operations, to the degree such markets exist. The three ISO/RTOs in the case study regions have adopted ancillary service definitions that allow provision with demand response directly in their markets, but this is not true of some other ISO/RTOs in the US. For example, the Northeast Power Coordinating Council (NPCC) complies with NERC ancillary service definition standards, but ISO New England (ISO-NE), an ISO/RTO within NPCC's jurisdiction, has not yet altered its market design to include DR resources in regulation markets. However, ISO-NE is testing these resources' ability to provide the services through an "out-of-market" pilot program (ISO-NE 2012). The open access transmission tariff filed with FERC by Public Service Company of Colorado (PSCo), the dominant BA in Colorado, identifies the various types of resources that may provide the different types of ancillary services (FERC 2010). Non-generation resources are specifically identified for each of the ancillary services as eligible to provide the service, with Supplemental Reserves explicitly identifying interruptible loads and pumped hydro storage as eligible resources. In spite of this, non-generation resources are unable to offer regulation and spinning reserves to PSCo because WECC has precluded such resources in its service definitions. Once WECC alters its service definitions, PSCo would be able to begin accepting non-generation resources as spinning reserves and regulation providers.

5. Attributes of Performance Barriers

Even if DR is eligible to provide various forms of AS, DR resources and their program providers may still have to overcome a number of barriers that originate at the BA due to its requirements to be an ancillary service provider. AS products and their associated qualification requirements were designed when the electricity system was made up primarily of large generators. Operating models for resources were fairly homogenous due to the similarity of operational characteristics of the fleet of generators. This led to rules that did not necessarily reflect the technical requirements of a service, but rather the focus was often on the technical capabilities of the existing resources that could provide that service. Given the stark differences in characteristics associated with other types of resource (e.g., demand response, battery storage) that were not considered when these operating models were designed and built, such resources have found it difficult to readily integrate themselves into the existing operating model, let alone capture any additional value that non-traditional but more flexible alternative resources could provide.

Demand response is a fundamentally different resource than a traditional generator. Individual DR resources vary substantially in size. In particular, they can be very small; far smaller than even the smallest of generators. The DR resource can be distributed behind several retail electricity meters, and often measured as part of a whole system of loads, some of which can and cannot be controlled for purposes of providing a bulk power system service. While it makes sense to require fast, continuous monitoring of each large generator that is providing a large amount of an ancillary service so that the system operator is immediately aware if the generator stops responding, this same requirement may not be appropriate for each individual load. The failure of an individual load to respond does not have the same reliability consequences and statistical methods for ensuring (and verifying) response of the DR resource in aggregate may be more appropriate (Kirby 2006). Ancillary services response and monitoring requirements should be based on the technical reliability requirements of the power system and not be defined based on the characteristics of the historic AS providers.

In spite of these differences, DR may be better suited than a generator to provide certain bulk power system services under certain circumstances. DR resources vary in the speed with which they can provide various bulk power system services; some can be considerably faster than traditional generators when automated (Eto et al. 2012). Many DR resources are more resilient to rapid changes in electricity consumption than traditional generators are to rapid changes in electricity production (i.e., cycling).

All of these differences make adapting the current operating procedures and market rules, which were developed largely for thermal generators, to alternative resource types difficult, but important in order to potentially gain access to these types of resource, and as such may require changes to those rules in order to address barriers to their participation.

In defining the performance attributes required to provide certain bulk power system services in ISO/RTO jurisdictions (ERCOT 2012a, b, c; IRC 2012; MISO 2012; PJM 2012a, b), ISO/RTOs have included rules and requirements that may limit the pool of eligible demand response resources to provide AS (e.g., limitations on resource size, the ability to aggregate multiple small resources, geographic boundaries of aggregation, and symmetric response capabilities).[6] Traditional generators are relatively large, (e.g., 100–2,500 MW) which resulted in bulk power system unit commitment and dispatch computer platforms being designed to deal with large units of power (i.e., whole or tenths of MWs). The resulting service requirements, therefore, largely relied on a common minimum resource size of 1 MW, but only the largest and most sophisticated individual customers are capable of providing a bulk power system service at so large a level. Recently, some ISOs (e.g., PJM and ERCOT) have begun to relax this size requirement (e.g., reducing minimum resource size to 0.1 MW) to promote entry of new technologies. DR program providers may also reach the minimum resource size requirement by aggregating many smaller, independently metered customers as a single DR resource portfolio. This is not always allowed in ISO/RTO markets, but some ISO/RTOs are implementing pilot projects to test viability in their systems (e.g., ISO-NE). Geographic boundaries exist in wholesale power markets which are based on physical limitations that have implications for the required procurement of certain bulk power system services (e.g., capacity, spinning reserves) and their settlement. ISO/RTOs, therefore, set rules on the geographic boundaries of aggregations of DR resources which may limit the ability of a program provider to meet the minimum resource size requirement. For regulation, a requirement for resources to provide equal capacity to move in both directions (i.e., reduce consumption and increase consumption) also effectively restricts the size of the pool of DR resources. This is due to the fact that many demand response resources may be more flexible in one direction than another (e.g., shedding load vs. increasing load). These types of rules impact the program provider's ability to make DR resources sizeable enough to enter the market and can severely limit aggregate participation, unless the ISO/RTO broadens the rules and provides mechanisms in their backend software to accommodate smaller and/or aggregated resources. These same types of issues also need to be addressed in non-ISO/RTO environments for DR (and other alternative flexible resources) to be considered on par with generation resources.

Table 3: Rules that limit the magnitude of the DR resource

	Min. Size (MW)	Aggregation Allowed	Symmetric Regulation Capacity Req'd
ERCOT	0.1	No*	No
MISO	1.0	No	Yes
PJM	0.1	Yes†	Yes
PSCo	N/A	N/A	N/A

* Pilots are underway to examine the ability to change this rule.
† Requires approval before it can be implemented.

Table 3 indicates the status of some of these barriers in the case study regions and illustrates the degree to which different jurisdictions have addressed the previously cited barriers. PJM has the most favorable rules for demand response participation, given its low minimum size threshold

[6] The term "aggregation of resources" is used here in a different context than the term "aggregator of retail customers" (ARC). As previously defined, ARCs are non-utility entities that offer opportunities for customers to act as a DR resource that provides a bulk power system service. An "aggregation of resources" simply refers to the ability to pool a group of disparate customers into a single portfolio for purposes of providing a bulk power system service in a DR program. Generally, state regulators and other policymakers determine if "aggregators of retail customers (ARCs) are allowed to offer DR programs. ISO/RTOs dictate if an "aggregation of resources" is allowed and if so what the conditions are for creating such a portfolio of participating customers.

and ability for ARCs and utilities to readily aggregate DR resources. ERCOT also has favorable market rules due to the ability to asymmetrically bid regulation capacity and its low minimum resource size. MISO has not gone as far as PJM and ERCOT in revising its market rules to facilitate entry by DR resources to provide ancillary services. At present, PSCo, the BA in Colorado, does not appear to have begun to deal with these issues.

6. Enabling Infrastructure Investment Barriers

Current DR programs are typically designed to elicit load reductions during periods of high system demand, when system reliability is threatened, and/or when electricity prices are very high. This approach generally limits customer interruptions to 8-20 times per year with duration limited to 2-6 hours each interruption. Participating customers can potentially rely on manual efforts (e.g., dimming lights, increasing thermostat set-points, shutting off equipment) to become a viable DR resource (although automation and control technology may increase the size and persistence of load curtailments from DR resources).

However, DR programs that provide ancillary services often require more frequent (e.g., several times daily) but much shorter (e.g., 10 minutes typically for spinning reserves) interruptions. Thus, in order to provide reserves and especially regulation, customers cannot rely on manual efforts to alter their consumption of electricity but rather must exclusively turn to control and automation technology to enable them to comply with control signals sent by the BA directly to the customer or via the program provider. Most customers do not inherently possess this type of control technology; thus, the size and scope of the necessary technology investment depends upon several factors including: how many of the customers' electricity consuming devices are to be controlled, what types of devices are to be controlled, and how fast the response will need to be to provide the ancillary service. There may also be ongoing costs associated with various types of control and automation technology. For example, the increased cycling of residential air conditioners or commercial chillers may increase the wear and tear on this equipment increasing operations and maintenance costs. These types of infrastructure investments may enable a customer to provide certain types of ancillary service, but additional costs must be incurred to adequately qualify as an AS provider.

ISO/RTO requirements to be an AS provider extend to the infrastructure that a resource must have to record its electricity usage on a time-scale consistent with the service being offered, to demonstrate its compliance with a dispatch signal and to transmit this information back to the system operator via a communications network. ISO/RTOs require an ability to measure a resource's performance as a bulk power system service provider. For services that don't require real-time visibility of response (i.e., capacity, energy and in some cases supplemental reserves), an interval meter at a customer's premise whose data can be polled and submitted to the ISO/RTO in bulk on a delayed basis has been deemed acceptable. For example, NYISO requires program providers to submit hourly meter reads of participating customers within 75 days after a declared emergency/capacity event (NYISO 2012). As the speed of response and system impacts associated with inaccurately measuring that response grows (i.e., spinning reserves, regulation), additional technology is typically required to accommodate more detailed, timely and transparent measurement and verification efforts under current rules. For example, resources that provide regulation have traditionally been required to possess technology which allows system operators the ability to follow their performance on a highly time-differentiated scale (i.e., 2-5 second telemetry). Some ISO/RTOs, like CAISO, require resources to transmit that information over a dedicated communications network that directly connects the DR resource or its program provider to the BA's system operations center. Customers who take service from a utility that has invested in Advanced Metering Infrastructure (AMI) already have digital interval meters installed but this equipment often times does not support real-time data transmission nor capture electricity consumption at 2-5 second intervals; thus additional equipment must likely be invested in to qualify as an AS provider. Telemetry equipment constitutes an additional large upfront investment with costs tending to increase with the speed of response required. Two of the three ISO/RTOs in our study have telemetry requirements for spinning reserves and all three ISO/RTOs require it for regulation.[7] Although not required in MISO, PJM or ERCOT, procuring a dedicated communications network results in both a capital cost to set up the network but also monthly service charges to maintain and use that network.

Taken jointly, these enabling infrastructure costs may serve as a sizable economic barrier to new entry of smaller customers, if it is required for each and every customer load that is being aggregated by a DR resource provider. These monitoring and verification requirements were developed when all AS were provided by large generators and they may not be technically justified for aggregations of small responsive loads. This particular barrier can be somewhat mitigated if the telemetry rules for DR resources are relaxed, as some ISO/RTOs have done, or the costs may be reduced if state entities subsidize the cost of this equipment to customers.

Table 4: Market rules impacting the cost of participation for DR resources

	Telemetry Rate	Telemetry for Spinning Res	Data Source Level	Dedicated Network Requirement
ERCOT	3-5 sec	Yes*	Aggregate	No
MISO	4 sec	Yes	Resource	No
PJM	2 sec†	No	Aggregate	No
PSCo	N/A	N/A	N/A	N/A

* Required for some resource types.
† May be batch sent every one minute

Table 4 indicates a sampling of market rules in the case study regions that impact part of the cost of enabling infrastructure. PJM has the most favorable rules for DR resources of the three ISO/RTO regions in our study which impose the least cost burden to provide various forms of AS. They allow aggregate data to be reported, their telemetry may be batch sent once each minute, and they do not require telemetry for spinning reserve.

[7] Telemetry, in this context, refers to additional metering requirements that the ISO/RTO imposes in order to have rapid meter readings be sent directly to the system operator for resource visibility purposes in real-time.

7. Revenue Availability Barriers

An analysis of the revenues for the two most valuable ancillary services (i.e., regulation and spinning reserves) can be used, in conjunction with explicit enabling infrastructure costs, to establish the payback period that could be supported by program providers looking to break into such markets.[8] We focus our efforts here on characterizing the level and variability of revenue that could have been derived in our three ISO/RTO study regions as well as the lone non-ISO/RTO region over the past several years, in order to present the boundary conditions for such financial calculations that a program provider would need to undertake when assessing the robustness of these markets to new entry.

7.1 ISO/RTO Regions

Organized wholesale markets run by ISO/RTOs provide a transparent source of valuation for DR resources and AS program providers on a temporal basis. The ancillary services market clearing price (MCP) that ISO/RTOs produce can be used as a proxy for the revenues that new market entrants could expect to receive in the near term. When analyzed jointly with the volume of capacity procured in an ISO/RTO market, DR resources and program providers can assess how much potential revenue is at stake for specific AS products. However, the potential impact of entry by several new low cost resources (e.g., certain types of demand response) on AS market prices in ISO/RTO environments is uncertain and may have the effect of lowering the clearing price (Woychik 2008).

7.1.1 ISO/RTO Market Clearing Price

The market clearing price of an ancillary service product is derived by a balancing area's system optimization algorithms (i.e., market software) and is basically equal to the sum of an availability bid and opportunity cost (generally determined through co-optimization with the energy markets) of the marginal supplier providing ancillary service capacity for each scheduled time period. In most ISO/RTO markets, all awarded resources are paid the MCP. MCP is recorded in units of $/MW-h, where MW-h represents the value of a MW of regulation or spinning reserves capacity held in reserve for an hour.

In the regions included in our study, the annual average MCP for regulation (up and down in ERCOT) ranged between ~$11/MW-h and $31/MW-h from 2009-2011(see Table 5). However, with the exception of ERCOT, prices have been steadily declining during this time period. Annual averages mask seasonal and weather effects (e.g., high prices in the spring due to large amounts of water run-off and absence of hydroelectric plants in the AS market) which may have caused this observed time trend (MacDonald et al. 2012). Thus, it is difficult to predict if prices will continue to drop over the next several years or will rebound to their 2009 levels. Such knowledge is vitally important to a DR resource or AS program provider who is considering entering such a market. If we assume that such prices are representative of those that could be achieved in the future and a program provider can construct a portfolio of DR resources that can provide regulation services for all hours of a 30-day month, these MCP values could yield revenues of $7.80 to $22.50 per kW-month. This reflects a difference in revenues of over 150%

[8] For reference, non-spinning reserves tend to be about 7% to 50% of the value of spinning reserves, depending on the ISO/RTO, while 30-minute supplemental reserves are less valuable than non-spinning reserves.

between markets but as little as 20% within a specific market (i.e., MISO) on an annual basis. Such uncertainty could make program providers shy away from entering certain markets, especially if it dramatically increases the risk that a program provider won't be able to enter into contracts with program participants for a period that allows them to fully recover the enabling infrastructure investment costs while making a profit. This is a particular concern in the state of Texas, given the variability in ERCOT's market prices and the typical duration of retail energy service contracts that have been observed in the Texas retail market.[9]

The annual average MCP for spinning reserve among ISO/RTOs is between $4/MW-h and $10/MW-h. Although these prices have stayed the same or increased between 2009 and 2011, as with regulation prices, these annual average values hide what may be short-term trends. For example, in 2011, the ERCOT region experienced brief periods of high prices that produced an anomalously high annual average of nearly $23/MW-h (MacDonald et al. 2012). Assuming a portfolio of resource could provide this service every hour in a 30 day month, this range in the value of spinning reserve would produce a monthly revenue stream of $2.90 to $7.20 per kW-month.

Table 5: Annual average market clearing prices for regulation and spinning reserves in U.S. ISO/RTOs

ISO (Reserve Zone)	Regulation (Combined or Up/Dn) ($/MW-h)			10-min Spinning Reserves ($/MW-h)		
	2009	2010	2011	2009	2010	2011
ERCOT	9.70/ 7.25	9.81/8.27	22.67/8.58	9.95	9.09	22.92
MISO	12.43	12.17	10.83	4.03	4.02	4.03
PJM*	23.51	17.95	16.42	4.83	5.72	7.91

* MCP for spinning reserve is for Mid-Atlantic reserve zone in PJM, while regulation MCP is for all of PJM
Darker cell shades indicate real-time markets, lighter are day-ahead markets

7.1.2 ISO/RTO Market Capacity Volume

Capacity volumes in ISO/RTO administered ancillary services markets vary by the size of a balancing area and how the balancing area determines its reserve requirements. Some BAs determine their requirements based on the forecasted load, while others base it on time of day, to reflect changing needs. Table 6 lists the average hourly capacity procurement in markets examined in this study. This data represents only the capacity that was purchased in the markets, and does not include any capacity that was self-scheduled or contracted bilaterally by market participants, for which data is not publicly available. The capacity reported for PJM's spinning reserve market is represented by the Mid-Atlantic Reserve Zone, which includes the State of New Jersey, while all other volumes reflect a market-wide procurement. On a capacity basis, ERCOT holds the most spinning reserve procured in its markets and PJM has the largest amount of regulation. But on a relative basis, when normalized by the system's 2011 average load, ERCOT procures the greatest share of both regulation (1.6% for either regulation up or regulation down) and spinning reserves (4.5%) of the three ISO/RTOs included in our study.

[9] Interviews with both program providers and Commission staff indicated that retail power contracts can range from one to 24 months, with most customers preferring shorter contract lengths.

Table 6: Average hourly in-market capacity procurement volume for some U.S. ISO/RTOs from 2009-2011

	Regulation (Combined or Up/Dn)		10-min Spinning Reserves	
	MW-h	% of Ave. Demand	MW-h	% of Ave. Demand
ERCOT	628/606	1.6%	1715	4.5%
MISO	396	0.6%	978	1.5%
PJM	824	1.0%	418	0.5%

Darker cell shades indicate real-time markets, lighter are day-ahead markets

The variation in the relative size of the market volume is likely due to several factors. The ability for loads and generators to self-schedule AS outside of the various markets may help explain why MISO and PJM have such small shares of their total capacity procured to provide regulation and spinning reserves. In addition, ERCOT's electric isolation from the larger two US interconnections makes it more vulnerable to rapid frequency loss during contingency events resulting in a requirement to carry larger amounts of ancillary services.

In spite of these relative differences, the ancillary services markets are still very small when compared to the wholesale energy markets in these ISO/RTOs. Traditional economic logic would suggest that a small market is unlikely to support a large number of new market entrants without substantially reducing the price. However, due to the co-optimization of energy and ancillary services, it is possible that the ancillary services MCP will be fairly robust to additions of new resources seeking to provide these services. MCP for ancillary services is largely driven by the opportunity cost of lost energy revenues. As the ancillary service market is only approximately 1% of the energy market, AS market clearing prices have limited impact on the overall system optimization. Thus, the opportunity cost component of MCP will likely remain constant even with large amounts of zero cost AS resources in the system. In fact, evidence of this exists currently, as ERCOT has approximately 50% of its synchronous reserve market satisfied by load, yet still has some of the highest MCPs for spinning reserve in the country. However, there will likely be a tipping point at which low cost resource penetration will cause MCP to begin to fall precipitously. Where that point exists, however, is not known nor has research been done in an attempt to identify it.

7.1.3 ISO/RTO Market Size

The market size gives an indication of how much money is available for potential DR program providers looking to develop a business model around offering ancillary services. Using the data for MCP and the capacity procurement volumes, an estimate of annual market size in dollars was calculated for the sample ISO/RTOs. Table 7 displays the annual market size of regulation and spinning reserve markets in the US in millions of dollars per year. The market size for 2009 for MISO could not be calculated because of incomplete data. The data suggests that the deepest AS market for spinning reserve is in ERCOT, even without the spike in 2011 which was largely due to a single month's extremely high prices, and for regulation in PJM, although ERCOT is relatively close behind.

Table 7: Annual market size of U.S. ISO/RTO regulation and spinning reserves markets

[M$/yr]		ERCOT	MISO	PJM
Regulation	2009	105	NA	160
	2010	118	43	126
	2011	152	38	123
Spinning Reserve	2009	119	NA	24
	2010	122	33	32
	2011	462	23	51

Darker cell shades indicate real-time markets, lighter are day-ahead markets

7.2 Non-ISO/RTO BAs

Unfortunately, a comparable comprehensive analysis of revenue for being an ancillary service provider in non-ISO/RTO BAs is not possible. Although the prices for the different ancillary services are available in the BA's FERC-approved tariff, the quantity that the BA provides to cover that fraction of the system requirement that is neither self-supplied nor forward-contracted for is not publicly available. This is the most comparable market volume metric to what we report for the ISO/RTOs. These non ISO/RTO BAs do not draw from a pool of external resources to meet a transmission customer's shortfall, but instead supply it from its own set of internal resources. Thus, in these non-ISO/RTO market environments, it is more likely that a vertically integrated utility would come to the BA with a DR program of their own for which they want credit against their AS requirements.[10] Because this volume of AS is completely outside of our scope of knowledge, we limit our assessment in non-ISO/RTO BAs to the level of prices paid for different forms of ancillary services.

BAs in non-ISO/RTO market areas annually submit a cost-of-service study to FERC to justify the rates they want to charge to transmission customers for use of the bulk power system as well as for procuring ancillary services on their behalf should they arrive without a balanced schedule. Although WECC doesn't allow DR resources to currently provide regulation, as previously mentioned, it is still illustrative to see what rates were filed by PSCo and approved by FERC for both regulation and spinning reserves in order to assess how much revenue could be available for a demand response resource wishing to provide these services. As Table 8 shows, the price in 2010 and 2011 for regulation (combined up and down) were identical ($16.202/MW-h) as were prices for spinning reserves ($16.526/MW-h). Data for 2009 was not available. These prices likely serve as the maximum, in the short-run, that a utility-sponsored DR program would offer their participating customers to provide the various ancillary services.

Table 8: PSCo Annual hourly point-to-point delivery price

	Regulation (Combined		10-min Spinning Reserves	
Year	2010	2011	2010	2011
Price ($/MW-h)	16.202	16.202	16.526	16.526

[10] For example, PacifiCorp has been using its CoolKeeper (DLC) program to satisfy part of its WECC requirements for non-spinning reserves for several years (Woychik 2008).

8. Revenue Capture Barriers

While an analysis of these wholesale and bilateral markets illustrates that there is money to be earned from providing various forms of ancillary services, a variety of barriers may exist that limits the ability for entities offering AS programs or DR resources participating in them to sufficiently capture this revenue to make the opportunity worth pursuing (see Table 9).

The uncertainty surrounding the availability of DR resources to provide ancillary service during different points in time and the measurement of their performance when scheduled lead to uncertainty in how much revenue a resource can expect to capture for providing these services. Some strategies that customers employ as a DR resource are available every hour of every day to provide certain types of ancillary services, but most have restrictions at different times of the day, days of the week, etc. that limits their availability to be an AS supplier. When coupled with the high volatility in market clearing prices that has been observed in some ISO/RTO ancillary services markets (see Table 5), predicting a reasonably accurate revenue stream over time that DR resources and their program providers in these jurisdictions might capture becomes challenging. This is exacerbated when considering that most methods used to measure demand response resources rely on meter data that includes both controllable loads, which are used to provide the bulk power system service, and uncontrollable loads, which are not and therefore subject to variability during the operating period. For some types of customers, divorcing the metering of controllable and uncontrollable loads at a site, thereby effectively sub-metering the loads that will respond to market control signals, should improve the accuracy of the measurement. This reduces revenue uncertainty but may increase enabling infrastructure investment costs.

Some of the ways in which DR resources interact with the ISO/RTO to provide a specific ancillary service can further inhibit their ability to capture certain kinds of revenue streams by limiting the quantity of a service the DR resource provides and/or is paid for. For example, a DR resource may be functionally capable of providing more than one bulk power system service (e.g., installed capacity, spinning reserves and regulation), but market rules may limit that DR resource to only provide a single service or restrict the size of the resource that can qualify to provide different services. Removing or relaxing these rules at the ISO/RTO may increase the amount of demand response that can be brought to market. Additionally, some system operators require DR resources to jointly bid into energy and ancillary services markets even if that resource only has the intention of providing an ancillary service. If the resource cannot economically provide energy for certain dispatch periods if called upon, the DR resource must either hedge itself against the risk of being dispatched with some sort of financial instrument, take itself out of the market for all bulk power system services during such times, or submit a very high energy bid in an attempt to prevent the system operator from dispatching it for energy but taking it as an ancillary service provider. If this requirement did not exist, the DR resource could fully bid its capability into the AS market at all times. Furthermore, in some jurisdictions (e.g., ERCOT), DR resources are not paid directly for the energy they provide the system when acting as an ancillary service provider. An inability to capture this revenue stream, which generators are provided with, may make it more difficult for a DR resource or an AS program provider to justify investments in enabling infrastructure. Interestingly, the DR resource’s supplier of electricity will actually capture much of this benefit, not the DR resource itself, if the wholesale price of electricity is substantially higher than the customer’s retail rate. Lastly, certain kinds of demand response can provide a fast and flexible resource capable of providing AS with potentially insignificant startup costs or startup time. Aside from meeting the basic bulk power system service definitions, providing a higher quality service based on such attributes is not valued in most current market designs. However, FERC, with its Order 755 (FERC 2011b) changed that by requiring organized wholesale markets to adopt methodologies where speed and accuracy of response will directly affect revenue streams. This, in turn, will likely improve the financial viability for DR resources and AS program providers.

Since it will most likely be vertically integrated utilities in these non-ISO/RTO BA environments that come forward with DR programs that provide AS, many of these barriers are more easily circumvented. For example, as long as there is a financial or regulatory incentive to do so, a vertically integrated utility can decide to allow or require sub-metering if it feels such is justified to more accurately measure the ancillary service a DR resource is providing. Likewise the utility can decide how best to dispatch its energy resources in these types of environments, thereby not requiring DR resources providing AS to offer up any energy. Additionally, the BA would not impose any obligations on having its DR resources be paid for any energy that is supplied; rather the utility's tariff would define what to do in such circumstances. Unless the utility can capture the value created when DR resources provide energy, the IOU would have no source of revenue to pay the participating customer for this energy, absent going out to its ratepayers to collect the money. The lone barrier in Table 9 that would likely directly apply is a multi-program restriction. The BA could require the utility to certify that its DR resources are not being credited against multiple bulk power system service requirements, but such rules have not been implemented by PSCo yet to our knowledge.

Table 9: Status of rules affecting revenue capture

	Allow Submetering	Must Bid Energy	Paid for Energy	Multi-Program Restrictions
ERCOT	No	No	No	No
MISO	No	Yes	Yes	No
PJM	Yes	No	Yes	No
PSCo	N/A	N/A	N/A	N/A

9. Program Provider Barriers

The structure and design of retail electricity markets also play a large role in influencing participation and interest in demand response, given the incumbent utility's unique role as the dominant interface between the wholesale power grid and the end-use customer. However, under traditional regulation, electric utilities have a regulatory model that itself may create barriers that limit their interest in pursuing DR resources as an ancillary service provider. Aggregators of retail customers, whose business operations are predicated on subscribing electric customers to demand response programs, have barriers of their own that limit their interest and ability to seek out DR resources willing to provide ancillary services.

9.1 Retail Electric Utility Environment

The traditional regulatory model for monopoly investor-owned electric utilities substantially drives their decision making surrounding most areas, demand response included. State regulatory commissions set and approve retail rates for IOUs through a regulatory process (i.e., rate case) designed to allow them to recover their prudently incurred costs and generate enough profit to gain access to capital by offering a reasonable rate of return on existing capital investments. Since these retail rates, for the most part, do not change considerably between rate cases, the utility has an incentive to reduce operating expenses and/or increase revenue (by promoting greater volume of retail electricity sales) in order to generate additional profit for its shareholders. Undertaking large capital investments does carry some risk, as regulators must inevitably approve what is eligible for cost recovery during a rate case, but also carry a reward, as regulators allow a rate of return on all acceptable capital expenditures at the utility's authorized return on equity which will increase the utility's allowable profit that rates are set to recover. Given this regulatory paradigm, IOUs have a business model that is not readily conducive for the pursuit of activities, such as energy efficiency or demand response, that will increase costs, reduce revenues, or defer future capital investment (see NAPEE 2007 for more details).

The history of demand response in IOUs illustrates the challenges this business model produced but also how utilities overcame them. In the 1970s, large industrial customers, seeking to reduce their own costs, demanded retail electric rates that would promote economic development. Out of concerns about the impacts such a large loss of these customers' load would have on utility revenues, IOUs developed the earliest forms of demand response–interruptible and curtailable (I/C) rates. These were designed to improve reliability, by giving the utility an opportunity to infrequently reduce electric service at a customer's facility (e.g., 20 times a year at most), while substantially reducing that customer's retail rate for that amount of load what was "non-firm" or interruptible. Regulators saw the benefit, both to the utility and its system from the increased reliability but also to the industrial customers by way of economic development, and were willing to approve the rate and allow the utility to recover any prudently incurred costs to implement it. Later that century, public policymakers and regulators wanted utilities to broaden their demand side management efforts (i.e., energy efficiency and demand response) as a way to further improve reliability, reduce system costs, and contribute to environmental sustainability. As a strategic response to this request, utilities sought to again pursue demand response activities (i.e., direct load control or DLC programs) provided regulators would authorize full and timely recovery of program costs and enable them to generate a return on the investment in control technology that they installed via retail rates. Under these conditions, such DR programs did not hurt the utility's bottom line nearly as much as energy efficiency efforts would, as they allowed the utility to retain load (thereby not reducing revenue), ratebase the investment in DLC technology (thereby earning a profit), while providing the utility with the ability to credit the peak demand reductions against planning reserve requirements (thereby reducing overall system costs). During the period between 1970s and mid-1990s (prior to restructuring), many utilities across the US brought forth such programs because they had solved the fundamental problem with the existing business model or facilitated retention of key customer loads (e.g. large industrials). With advancements in technology over the past ~20 years coupled with increasing interest of customers to have some ability to override a control signal, utilities began to move away from traditional DLC devices towards more flexible and customer-controllable technologies, like programmable controllable/communicating thermostats, to provide these types of demand response opportunities. It has now become difficult for utilities to claim these devices should qualify as a utility capital investment, since customers could readily pursue this technology on their own at relatively low cost, and that the utility should continue to be the exclusive program provider, as technology (e.g., AMI) had created opportunities for outsourcing and the advent of wholesale electricity markets have created opportunities for third-party DR program providers to emerge as a viable competitor. As such, the traditional utility approach to such forms of DR is being substantially challenged at present.

Historically, interruptible/curtailable tariffs and DLC programs were activated during system emergencies and in some cases, to respond to high prices in energy markets. However, IOUs face a somewhat different set of challenges when assessing if a business case exists for creating and offering either expanded or new DR programs that target reserves and regulation services. DR programs that provide ancillary services will produce financial benefits, but such benefits are difficult for the utility to capture. For example, if the provision of operating reserves from customers allows a vertically integrated utility to more efficiently operate its fleet of generation assets, the utility's operating expenses can be reduced in the form of lower fuel and purchased power budgets as well as reduced non-fuel operations and maintenance costs. Any reduction in operations and maintenance costs would go to the utility's bottom line but only up until the next general rate case is filed and new rates reflective of these lower costs go into effect. Savings in fuel and purchased power budgets from DR resources providing AS, which would occur if the utility uses its own generation assets to provide ancillary services or must go out to the market to procure it, are generally passed directly through to customers via a fuel adjustment clause, leaving the utility with little to no ability to profit from any reductions in these costs. However, should these types of DR programs result in an opportunity to convert that reserved generation capacity into energy and sell off-system at a profit, regulators have struck various deals with utilities that require some, most, or all of the net proceeds to be returned to ratepayers. For example, Wisconsin does not allow the utility to retain any profit from an off-system sale (Wisconsin Administrative Code 2012), whereas Public Service of Colorado can retain up to 20% of the net proceeds (Colorado PUC 2009). Lastly, increased demand for ancillary services may necessitate the building of new generating stations in the future to accommodate this need. If DR resources are instead relied on to provide such services, the need to invest in this new capacity would be deferred or mitigated outright thereby causing the utility to forego a potential profit opportunity.

Aside from business model issues, the incumbent retail electric utility has other challenges offering these types of DR programs. As stated above, traditional forms of demand response, like those predominantly and historically offered in Colorado, Texas, Wisconsin and New Jersey, have focused on providing bulk power system services that exclusively inure from reducing electricity consumption (e.g., DLC, I/C) just a few times each year with duration of only a few hours each time. DR program designs that target ancillary services markets will need to fundamentally change to accommodate more frequent but shorter duration events and may require customers to both reduce and increase load, in the case of frequency regulation, as they follow dispatch signals from the ISO/RTO's or the BA's control center. Although the system operator in the control center is the originator of such control signals, a clear conflict of interest arises when a utility, who is managing and subscribing customers to such programs, could profit from the increased consumption of electricity. Additionally, utility tariffs are designed to treat customers as a group and not allow the utility to price electric service differentially for each and every customer (i.e., price discrimination). In order to provide the BA with the appropriate amount of ancillary services being called for, the IOU may have to differentially dispatch DR resources such that some customers are called upon more or less than others and get compensated accordingly. This differential treatment poses challenges to the traditional regulatory compact under which utilities' generally operate.

Thus, state regulators continue to play an important role in allowing and inducing investor-owned utilities, either vertically integrated or facing retail competition, to pursue such DR opportunities. Tariffs must be changed that allow the utility to offer programs to customers that substantially alter performance requirements and dispatch conditions from previous DR programs. Regulators must also address the shortcomings in the current business model to induce utilities to pursue these types of programs. First, regulators can guarantee timely cost recovery of prudently incurred costs to design, implement and maintain these types of AS programs.[11] Additionally, they can continue the tradition of allowing the utility to earn a rate of return on the necessary enabling infrastructure investments that a customer must undertake to provide AS or alternatively find other methods for making this endeavor profitable for the utility. Lastly, regulatory commissions can consider different approaches for altering a utility's tariff to allow for it to capture more of the profit that may be generated from changes in the operations of its generation fleet (if it has not been divested of them) and to differentially dispatch and/or provide different performance payments for customers participating in a DR ancillary services program. To date, none of the states in this study have undertaken a comprehensive assessment of what it would take to induce utility's to provide these types of opportunities to customers, but based on our interviews Texas appears ready to do so in the near future.

9.2 Aggregators of Retail Customers

The formation of ISO/RTO wholesale markets created an opportunity for non-utility entities to see and capture value in subscribing customers to provide various forms of bulk power system services. However, these aggregators of retail customers must contend with their own set of unique barriers which can limit or hinder their ability to offer such programs.

[11] Regulators may question the value of spending ratepayer dollars to invest in the back office systems and other forms of technology required to operate such programs when another entity (i.e., ARC) who has already done so could offer such programs at a fraction of the cost. Outsourcing of these types of programs, therefore, could be a concern for IOUs.

State regulators can be uncomfortable relinquishing control over DR programs to private sector entities that are largely unregulated. The level of oversight given by state governmental bodies of ARCs is often times far less than state regulators impose on electric utilities under their jurisdiction. ARCs generally must conform to program rules set by ISO/RTOs that themselves are regulated by FERC. One state regulatory staffer indicated when interviewed that this can create a conflict, whether perceived or real, between state and federal jurisdictions. Often times, ARCs do not supply electricity to their program participants yet their programs affect the timing and amount of electricity consumed. Regulators and utilities alike have concerns about the implications this can have on the efficient and economical procurement of energy for these customers. Taken in totality, a few state regulators (e.g., Wisconsin) have outright prohibited the operation of ARCs; while in other states, regulators have required the utility to outsource DR programs to ARCs (e.g., Colorado); while still in others they are freely allowed to subscribe customers to their own programs (e.g., Texas and New Jersey). Such decisions that limit the opportunities for ARCs to offer programs to customers, however, may result in an inability for DR to reach its full potential if the utility is unable to overcome its own set of barriers to offer such DR programs (as discussed above).

In non-ISO/RTO BA environments, it is the BA itself (or its associated IOU) that is supplying the bulk power system services to transmission customers who arrive without a balanced schedule. As such, ARCs have no real buyer of the bulk power system services they may be able to offer, except a utility. Thus, they must work with the utilities within the balancing authority's footprint or have regulators require the ARC to either manage a DR program on behalf of the IOU or have that program outsourced to them entirely.

If ARCs are able to participate directly in ISO/RTO markets, they must find the endeavor sufficiently profitable in order to pursue it. Given the volatility in ISO/RTO AS market revenues (see Sections 7 and 8), an ARC in such jurisdictions must be able to lock in a customer for a sufficient length of time to ensure it can pay off whatever initial investment is made in automation and control technology that is necessary to enable a customer to provide the contracted-for ancillary service. For example, in ERCOT's territory, there is considerable uncertainty in customer retention for retail energy providers. Although some customers sign contracts with a service provider for as much as 24 months, most customers do not. There is a very real risk that customers will change providers before reaching the end of the payback period on a DR enabling infrastructure investment, which makes the decision to enter such markets challenging.

9.3 Inducing Customer Participation

For utilities or ARCs to provide ancillary services to a BA, they must inevitably recruit customers into a program and convince them to accept, if not directly invest in, the necessary automation and control technology required to provide ancillary services. This requires education, marketing and technical assistance to ensure that the customer is fully aware and capable of providing the ancillary service for which they are being paid. ARCs and utilities alike must overcome customer hesitancy surrounding the installation of systems that relinquish control of some electricity consuming devices to a third-party. Customers must be convinced that the program provider is acting in their best interest when dispatching them for an event and adjusting their consumption of electricity via the control technology.

Just as there is competition for customers between utility-sponsored and ARC-sponsored programs, there can be competition for customers between energy efficiency and demand response programs. In some applications, energy efficiency efforts can actually undermine demand response capabilities. The more these programs compete with each other and are not integrated or coordinated in their program development and delivery efforts, as is the case in Colorado, Wisconsin and New Jersey but not Texas (Goldman et al. 2010), the more challenging it will be to achieve robust DR and EE programs.

Additionally, certain program providers specialize in providing specific services (e.g., Enbala Power Networks® focuses on providing regulation services and more recently load following) or recruiting specific loads (e.g., EnerNOC, Inc. generally subscribes commercial and industrial customers), but a customer site might have many different types of controllable loads that are good candidates to provide different types of bulk power system services. Customers should have the option of being represented by more than one program provider and/or enrolling in more than one DR program if they have a variety of controllable loads that are amenable to do so.

Customers also need to have enough money on the table to induce their participation. As noted above, the level of payments given for providing an ancillary service is both volatile and may decrease with increased participation. The cost of the enabling infrastructure investments to meet bulk power system service definitions may require an extended payback period when relying on the payments from participation in an ancillary services DR program alone. As such, a customer (or its program provider) may need to consider pairing enrollment in an ancillary service program with another DR program, to the degree such is allowed, that can leverage the technology investment. In the end, customers must see sufficient value both in the short and long-term, given the lengthy payback period for the enabling control technology required to provide such ancillary services, in order to subscribe to such programs.

Table 10: Status of issues affecting program providers

	Opportunities for ARCs	Viable Utility Business Model	Coordination of EE and DR Activities
Texas	Yes	No	No
Wisconsin	No	No	Yes
New Jersey	Yes	No	Yes
Colorado	Limited*	Limited†	Yes

* ARCs currently are only able to act as a third-party DR program provider.
† PSCo is allowed to retain 20% of the net revenues from off-system sales associated with excess electricity production.

10. Conclusion

Increasing penetration of variable renewable resources in US electricity markets is likely to require operational changes and procurement of greater quantities of various bulk power system services. Although these services have been traditionally provided by generators, demand response has been identified as one of several alternative resources that could also serve this need. Conceptual studies and actual demonstrations have illustrated that certain forms of DR resources are well-suited to provide AS to the grid due in part to their fast response, distributed nature and the statistical reliability of large numbers of smaller resources. DR resources may also have the ability to be brought to market much more quickly than a comparably-sized generation resource that must go through the lengthy permitting, siting and regulatory approval process.

However, the interest in fostering demand response participation in ancillary services markets requires the opportunity to provide such services, a clear financial incentive to do so and the market and regulatory structures to capture this value. This study identifies the various barriers standing in the way of more widespread deployment of demand response resources as a provider of ancillary services.

As Table 11 summarizes, regional reliability councils must first allow DR resources to provide ancillary services by defining them in such a way that IOU or ARC DR programs are not precluded, either implicitly or explicitly, from doing so.[12] Once the opportunity is there, BAs promulgate rules that define the infrastructure and performance attributes of a DR resource wishing to provide such services that are brought to market directly or via a program provider. These rules may create barriers, either physical or financial, that limit the ability of a DR resource or program provider to provide these services. When taken in conjunction with expected revenue streams and an ability to capture this revenue as an AS provider, barriers that relate to the cost effectiveness of these resources are revealed which can limit DR from reaching its full potential. The regulatory compact between utility and state regulators, along with other statutes and decisions by state policymakers, may also create barriers that program providers must overcome in order to pursue DR resources more vigorously as an ancillary service provider.

Table 11: Applicable entities and organizations responsible for and affected by barriers

	Reliability Council	BA	IOU	ARC	Utility Regulator	End-use Customer
Bulk Power System Service Definitions	✷	✷,●	●	●		
Attributes of Performance		✷	●	●		●
Enabling Infrastructure Investments		✷	●	●		●
Revenue Availability		✷	●	●		
Revenue Capture		✷	●	●		●
Program Providers		✷	●	●	✷	●

✷ - Entity/Organization responsible for creating the barrier
● - Entity/Organization affected by the barrier

[12] For a more comprehensive listing of specific barriers and the entities and organizations responsible for and affected by these barriers, see Appendix A – Entity/Organization Responsible for and Affected by Barriers.

One of the most effective ways to remove these barriers is to alter the requirements imposed on DR resources wishing to provide AS (see Table 12).[13] By acknowledging that demand response is fundamentally different than a generator, many ISO/RTOs are currently finding ways to alter the requirements to provide these services such that the quality of the service they are procuring is maintained but the pool of resources that can provide it is expanded. In contrast, most non-ISO/RTO BA environments do not appear to be as far along in their attempts to better integrate non-traditional resources as ancillary service providers. Where DR resources are able to provide AS, advancements in technology through research and development efforts and/or increased market adoption will likely cause the cost of automation and control technology and other forms of enabling infrastructure investments to continue to drop making participation as an AS provider more cost effective. Increases in benefits, through market rule changes (e.g., scarcity pricing, reserve demand curves) can likewise contribute to an increase in the cost effective procurement of AS from demand response. Finally, altering the process by which program providers do business (e.g., changes in the utility's business model) should help facilitate increased interest on their part in pursuing DR resources as a viable provider of AS.

Table 12: Actions required to overcome barriers

	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Bulk Power System Service Definitions	◆				
Attributes of Performance		◆			
Enabling Infrastructure Investments		◆		☐	
Revenue Availability					◆
Revenue Capture		◆			
Program Providers			◆	☐	☐

◆ - Primary action to overcome barrier
☐ - Secondary action to overcome barrier

The four regions focused on in this study illustrate these various barriers and ways in which the regions have or are attempting to address them. Colorado has a vertically integrated retail utility environment that operates within a non-ISO/RTO BA footprint, where the regional reliability organization (WECC) allows DR resources to provide spinning reserves but not regulation. The existing wholesale market environment results in little to no opportunity for ARCs to directly solicit customers and bring DR resources forward to provide AS unless there is someone on the other end to buy their services. The BA does not provide such a "marketplace", so the ARCs must develop relationships with the utilities in the BA's jurisdiction in order to play some sort of role. The investor-owned utilities, as the sole provider of electricity service to customers, have only modest profit motives to pursue non-generation resources, like DR. Colorado utilities and state regulators have not placed expansion of DR to provide ancillary services as a high priority given the excess capacity situation currently experienced by the state's utilities. If the capacity situation tightens and/or the distribution system requires attention due to increased penetration of distributed variable renewable resources, which may occur later this decade, state regulators as well as the utilities could be more inclined to consider such new DR opportunities.

[13] For a more comprehensive listing of specific barriers and the actions that can be overtaken, see Appendix B – Action Required to Overcome Barriers.

Texas, with its open retail market and ISO/RTO wholesale market, appears to have conditions that are highly conducive for DR resources to readily provide ancillary services. ERCOT has indeed attracted a substantial amount of demand response to its markets, enrolling ~2,400MW of capacity to provide spinning reserves (Patterson 2011). The vast majority of this is provided by large industrial facilities utilizing under-frequency relays that were installed through utility-sponsored instantaneous interruptible tariffs years prior to the advent of the organized wholesale market (Zarnikau 2010). While ERCOT has been very successful at operating with sizable amounts of ancillary services (i.e., up to 50%) provided by large DR resources, relatively few new and substantially smaller DR resources have been brought to market. Conversations with program providers and regulatory staffers illustrate the challenges that the open retail market creates when trying to attract these smaller DR resources. The distribution utilities, who no longer have supply obligations to customers, have little profit motive to pursue such programs, which means regulators must get involved to either create the business case or mandate that programs be offered. Competitive retail electricity suppliers do not yet readily see a value proposition in offering the requisite types of enabling technology as an additional service due in part to short customer contract lengths which do not exceed the return on investment hurdle rates on the equipment. The current wholesale "energy-only" market design does not provide a reservation payment that guarantees a longer term (e.g., quarterly, semi-annual, or annual) revenue stream compared to other ISO/RTOs that administer capacity markets. This adds risk into the decision to invest in enabling infrastructure at customer premises. Reserve margins that exceeded ERCOT requirements by 2-4 percentage points coupled with major changes at ERCOT to a nodal market over the last several years resulted in time and effort not being directed towards creating greater opportunities for DR resources to participate in the market. Although with more recent reserve shortages, ERCOT and the Texas Public Utility Commission are jointly working through the stakeholder process to resolve these issues and improve the environment for DR in general (see Public Utility Commission of Texas Project No. 40000 for more details).

New Jersey is in a similar situation as Texas but for somewhat different reasons. Like ERCOT, PJM, the ISO/RTO that covers New Jersey, allows DR resources to provide spinning reserves and regulation. The existing utilities' business model, however, creates little incentive for distribution utilities to pursue new DR resources in any fashion, let alone as an ancillary service provider. New Jersey allows retail competition and utilities currently provide electric commodity and ancillary services as a bundled product for default service customers through a multi-year contracting (i.e., auction) process. The costs of this bundled product are completely passed through to these customers, which provides little incentive for the utility to pursue lower cost options to provide these services *outside of the auction process* nor any ability to do so within the auction process since the products are bundled. So even though PJM is on the forefront of creating and expanding opportunities for DR resources to provide various forms of ancillary services, it is only ARCs or competitive retail providers going directly to the market or through bilateral contracts with third-party suppliers[14] who are likely to bring resources to market, absent state regulatory engagement.[15]

Wisconsin, with its regulated retail environment and restriction on ARCs providing DR programs, faces both regulatory and utility business model barriers that limit their utilities' interest in pursuing DR resources as a provider of ancillary services within MISO. Electric utilities in this state are vertically integrated. Since they rely on their own generation assets to serve customers' needs, any reductions in non-fuel operating expenses from more efficiently operating this fleet of resources can be captured by the utility but only until new rates are set which reflect these now lower costs. Although these types of DR programs also create an opportunity for the state's utilities to convert reserved generation capacity into energy which can be sold off-system, state regulators do not allow the utility to retain any of these profits but instead require the utility to turn them over to ratepayers. Furthermore, the electric utilities profit from investing in capital assets, like new generating stations, which is often not true for DR investments. As such, Wisconsin utilities have only modest financial incentives to pursue DR in general, while state regulators have restricted ARCs from doing business in the state. Should state regulators choose to alter the utility's business model making the pursuit of DR resources as a provider of AS more lucrative, the utility must alter its existing tariff to expand the conditions under which current and future DR resources can be dispatched. Regulators could also choose to lift their moratorium on ARCs to further facilitate access to DR resources that can provide ancillary services. However, at this time, based on our interviews, the Commission does not appear inclined to look into these issues in the near future.

These four regions included as case studies in this report are likely representative of the experience in similar wholesale and retail market environments across the country. Our assessment of the barriers to demand response resources associated with smaller customers who must go through a program provider in order to provide ancillary services illustrates that the issues span nearly all entities and organizations in the chain that connects wholesale markets to retail customers. Fundamentally, in a highly regulated system incentives must be aligned among the balancing authority, utilities, and program providers in order for DR to reach the system operator, where AS is procured. Most of these entities have little to no incentive to address the identified barriers on their own, even if society as a whole could greatly benefit from the effort. Thus, many different but disparate parties will need to work together for the common good in order for smaller DR resources to reach their full potential as a provider of ancillary services.

[14] Third-party electricity suppliers provide capacity, energy, and ancillary services as a portfolio to competitive electricity suppliers or the incumbent utility for default service. The goal of third-party suppliers is to provide the product at least-cost, which may entail pursuing DR as a resource within the portfolio.

[15] The New Jersey Board of Public Utilities (NJBPU) in 2008 did get involved by ordering the utilities to augment DR program payments for new resources participating in PJM's 2009 Interruptible Load for Reliability (ILR) program through a series of one-year pilots with a goal of fostering cooperation with ARCs (NJBPU 2008). Two years later, the NJBPU stopped all utility pilot programs due to a lack of funding; leaving ARCs to continue enrolling customers directly in PJM programs without any augmented payment (NJBPU 2010).

11. References

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12. Appendix A – Entity/Organization Responsible for and Affected by Barriers

Legend

✸ = Entity/Organization is responsible for creating the barrier;
○ = Entity/Organization is directly affected by the barrier

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Bulk power system service definitions	**Rules do not explicitly identify any form of demand response and/or storage resource as being eligible to provide any form of ancillary services**	Excludes all forms of demand response and/or storage resources from providing any form of ancillary service	✸	✸		○	○		
Bulk power system service definitions	**Rules explicitly identify specific forms of demand response (e.g., interruptible) and/or storage (e.g., pumped hydro) resources as being eligible to provide certain forms of ancillary services**	Excludes certain forms of demand response and/or storage resources from providing certain forms of ancillary services	✸	✸		○	○		
Attributes of Performance	**Rules impose certain size restrictions on magnitude of demand response and/or storage resources response capabilities (e.g., 1 MW, 0.1 MW)**	Excludes smaller forms of demand response and/or storage resources		✸	✸	○	○		
Attributes of Performance	**Rules impose certain geographic restrictions on participation (e.g., transmission zone) that are not technically warranted for reliability reasons**	Excludes aggregations of demand response and/or storage resources spanning different geographic locales		✸	✸	○	○		
Attributes of Performance	**Rules impose certain restrictions on timing of response capabilities (e.g., 6 second, 5 minute) that are not technically warranted for reliability reasons**	Excludes forms of demand response and/or storage response where communication latency and ramping requirement exceeds response time requirements (exacerbated if communications requirements include sending dispatch signals via TO, see communications barrier)		✸	✸	○	○		

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Attributes of Performance	**Rules impose certain restrictions on duration of response capabilities (e.g., 30 minutes) that are not technically warranted for reliability reasons**	Excludes forms of demand response and/or storage response where duration of response requirement exceeds length of time the resource can provide service before being completely depleted		✸	✸	○	○		
Attributes of Performance	**Rules impose symmetric response requirements to provide a bulk power system service (e.g., identical capacity for regulation up and regulation down)**	Potentially limits the amount of the bulk power system service that could be provided by certain forms of demand response and/or storage		✸	✸	○	○		
Enabling Infrastructure Investment	**Rules impose certain restrictions on communications (e.g., security, network requirements, use of standard protocols, signal speeds for automatic generation control)**	Excludes forms of demand response and/or storage response where communication latency exceeds response time requirements		✸	✸	○	○		
Enabling Infrastructure Investment	**Complying with ancillary service event performance requirements may expose equipment to conditions that void warranties, reduces its useful lifetime, etc.**	Limits various demand response and/or storage resources from participating in ancillary services programs				✸	✸	✸	○
Enabling Infrastructure Investment	**Rules impose certain restrictions on ability to directly receive and respond to dispatch signals (e.g., Automatic Generation Control) that are not technically warranted for reliability reasons**	Excludes aggregations of demand response and/or storage resources because of cost to comply with bulk power system product requirement		✸	✸	○	○		
Revenue Availability	**Benefits that can be captured are uncertain due to a variety of factors (e.g., high historic price volatility, thin A/S market volumes, level of penetration of renewable generation)**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services		✸	✸	○	○		○

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Revenue Capture	**Rules impose restrictions on participants being subscribed by more than one program provider that are not technically warranted for reliability reasons**	Potentially limits the Balancing Authority from taking full advantage of all services a customer could provide if program providers don't offer programs that supply the full range of bulk power system services		✸	✸	○	○		
Revenue Capture	**Rules impose restrictions against participants providing certain combinations of bulk power system services (e.g., operating reserves and capacity) that are not technically warranted for reliability reasons**	Potentially limits the Balancing Authority from taking full advantage of all services a customer could provide if program providers don't offer programs that supply the full range of bulk power system services		✸	✸	○	○		
Revenue Capture	**Market rules impose restrictions against participants providing certain combinations of bulk power system services (e.g., operating reserves and capacity) that are not technically warranted for reliability reasons**	Limits interest in programs to only the most lucrative (i.e., cost effective) ones when a choice must be made between competing program options		✸	✸	○	○		○
Revenue Capture	**Rules, in certain co-optimized systems, impose bidding requirements for both energy and various ancillary services**	Excludes forms of demand response and/or storage who are unable to cost-effectively provide energy for an extended length of time		✸	✸	○	○		
Revenue Capture	**Rules, in certain co-optimized systems, impose payment requirements that preclude reimbursement for energy and/or "mileage" provided by Ancillary Service resources**	Excludes forms of demand response and/or storage who are unable to cost-effectively provide such services without these payments		✸	✸	○	○		

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Revenue Capture	**Accuracy of response to dispatch signal is not valued appropriately**	Limits demand response and/or storage resources from capturing total value provided to Balancing Authority, if fewer resources would have been required to provide bulk power system services		✸	✸	○	○		
Revenue Capture	**Baseline forecasting of demand has high uncertainty and a lack of accuracy**	Potentially affects performance calculations thereby affecting value capture for IOU/Aggregator who must subscribe large enough resources who can more accurately produce baselines or oversubscribe aggregations of resources to manage these inaccuracies		✸	✸	○	○		
Revenue Capture	**Rules impose certain restrictions on sub-metering that are not technically warranted for reliability reasons**	Potentially reduces accuracy in baseline estimates of usage which may affect performance calculations thereby affecting value capture for IOU/Aggregator		✸	✸	○	○		
Program Provider	**Aggregators required to bid their demand response and storage resources participating in programs into wholesale markets via the participating customers' Load Serving Entity**	Limits Aggregators from offering such services		✸	✸	○	○		
Program Provider	**IOUs unable to differentially dispatch and pay customers on the same ancillary service program**	Precludes IOUs from offering any ancillary services programs to aggregations of demand response and/or storage resources				○		✸	

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Program Provider	**States exclude Aggregators from running their own programs, independent of the IOU**	Precludes Aggregator from offering any ancillary services programs to any form of demand response and/or storage resources					○	✸	
Program Provider	**State regulators do not support a third-party DR program provider model**	Precludes Aggregator from offering any ancillary services programs to any form of demand response and/or storage resources		○			○	✸	
Program Provider	**Software and back-office systems to dispatch and process demand response and/or storage resources as ancillary services providers must be authorized by applicable (regulatory) authority**	Affects interest in ISO/RTO/BA and IOU to pursue demand response and/or storage resources to provide ancillary services due to risk of cost-recovery		○	✸	○		✸	
Program Provider	**Ancillary services costs are generally a pass-through to ratepayers**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services		○		✸		✸	○
Program Provider	**Reliance on demand response and/or storage resources as ancillary service providers may reduce total sales**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services		○		✸		✸	○
Program Provider	**Limited profit motive in short-run for pursuing demand response and/or storage resources as ancillary service providers**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services		○		✸		✸	○
Program Provider	**Reliance on demand response and/or storage resources as ancillary service providers may reduce profits in long-run (i.e., defer need for adding new generation resources)**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services		○		✸		✸	○

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Program Provider	**Frequency and duration of ancillary services events that are not technically warranted for reliability reasons may exceed some customers willingness to participate**	Limits various demand response and/or storage resources from participating in ancillary services programs				✸	✸	✸	○
Program Provider	**Complying with ancillary service event performance requirements may cause electricity bill to rise due to retail rate design (e.g., ratcheted demand charge, real-time pricing)**	Limits various demand response and/or storage resources from participating in ancillary services programs				✸	✸	✸	○
Program Provider	**Retail Energy Provider contracts in deregulated markets are too short to provide enough revenue potential to merit capital investments in DR enablement**	Limits interest in demand response, especially in enabling loads to provide more M+V intensive products				✸	○	✸	○
Program Provider	**Rules impose certain financial/credit requirements (e.g., posting a bond)**	Excludes forms of demand response and/or storage who do not have the financial resources to meet met the requirements		✸	✸	○	○		
Program Provider	**Program administration, program compliance (e.g,. telemetry, metering) and control technology (e.g., EMCS) costs to enable specific kinds of demand response and/or storage resources to comply with specific ancillary services reliability and market rules that are not technically warranted for reliability reasons is high**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services		✸	✸	○	○		○

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Program Provider	**Benefits provided by DR and storage resources to the grid that can be captured, because externalities to the market are not reflected, are too low relative to costs to enable specific kinds of demand response and/or storage resources to comply with specific ancillary services reliability market rules**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services		✸	✸	○	○		○
Procedural	**Market rule changes to correct observed problems with market products at Balancing Authority level must successfully navigate stakeholder working group and committee structure**	Extends the time required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services Presents a free rider problem where the entity that does all the work to get rules changed provides benefits to all other potential DR suppliers		✸	✸	○	○		
Procedural	**Regulatory change to correct observed problems with state-level DR program offerings and/or business models for such programs must successfully navigate the regulatory process**	Extends the time required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services Presents a free rider problem where the entity that does all the work to get rules changed provides benefits to all other potential DR suppliers				✸	○	✸	

Category	Barrier	Consequence	Reliability Council	BA	Federal Utility Regulator	IOU	ARC	State Utility Regulator	End-Use Customer
Procedural	**Market rule changes to correct observed problems with market products at Balancing Authority level must successfully navigate stakeholder working group and committee structure**	Potentially extends the time and cost required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services Presents a free rider problem where the entity that does all the work to get rules changed provides benefits to all other potential DR suppliers		✸	✸	○	○		○

13. Appendix B – Action Required to Overcome Barriers

Legend

■= Primary action to overcome the barrier

☐ = Secondary action to overcome the barrier

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Bulk power system service definitions	**Rules do not explicitly identify any form of demand response and/or storage resource as being eligible to provide any form of ancillary services**	Excludes all forms of demand response and/or storage resources from providing any form of ancillary service	■				
Bulk power system service definitions	**Rules explicitly identify specific forms of demand response (e.g., interruptible) and/or storage (e.g., pumped hydro) resources as being eligible to provide certain forms of ancillary services**	Excludes certain forms of demand response and/or storage resources from providing certain forms of ancillary services	■				
Attributes of Performance	**Rules impose certain size restrictions on magnitude of demand response and/or storage resources response capabilities (e.g., 1 MW, 0.1 MW)**	Excludes smaller forms of demand response and/or storage resources		■			
Attributes of Performance	**Rules impose certain geographic restrictions on participation (e.g., transmission zone)**	Excludes aggregations of demand response and/or storage resources spanning different geographic locales		■			
Attributes of Performance	**Rules impose certain restrictions on timing of response capabilities (e.g., 6 second, 5 minute) that are not technically warranted for reliability reasons**	Excludes forms of demand response and/or storage response where communication latency and ramping requirement exceeds response time requirements (exacerbated if communications requirements include sending dispatch signals via TO, see communications barrier)		■			

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Attributes of Performance	**Rules impose certain restrictions on duration of response capabilities (e.g., 30 minutes) that are not technically warranted for reliability reasons**	Excludes forms of demand response and/or storage response where duration of response requirement exceeds length of time the resource can provide service before being completely depleted		■			
Attributes of Performance	**Rules impose symmetric response requirements to provide a bulk power system service (e.g., identical capacity for regulation up and regulation down)**	Potentially limits the amount of the bulk power system service that could be provided by certain forms of demand response and/or storage		■			
Enabling Infrastructure Investment	**Rules impose certain restrictions on communications (e.g., security, network requirements, use of standard protocols, signal speeds for automatic generation control) that are not technically warranted for reliability reasons**	Excludes forms of demand response and/or storage response where communication latency exceeds response time requirements		■			
Enabling Infrastructure Investment	**Complying with ancillary service event performance requirements may expose equipment to conditions that void warranties, reduces its useful lifetime, etc.**	Limits various demand response and/or storage resources from participating in ancillary services programs			■		
Enabling Infrastructure Investment	**Rules impose certain restrictions on ability to directly receive and respond to dispatch signals (e.g., Automatic Generation Control) that are not technically warranted for reliability reasons**	Excludes aggregations of demand response and/or storage resources because of cost to comply with bulk power system product requirement		■		□	
Revenue Availability	**Benefits that can be captured are uncertain due to a variety of factors (e.g., high historic price volatility, thin A/S market volumes, level of penetration of renewable generation)**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services				□	■

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Revenue Capture	**Rules impose restrictions on participants being subscribed by more than one program provider that are not technically warranted for reliability reasons**	Potentially limits the Balancing Authority from taking full advantage of all services a customer could provide if program providers don’t offer programs that supply the full range of bulk power system services		■			
Revenue Capture	**Rules impose restrictions against participants providing certain combinations of bulk power system services (e.g., operating reserves and capacity) that are not technically warranted for reliability reasons**	Potentially limits the Balancing Authority from taking full advantage of all services a customer could provide if program providers don’t offer programs that supply the full range of bulk power system services		■			
Revenue Capture	**Market rules impose restrictions against participants providing certain combinations of bulk power system services (e.g., operating reserves and capacity) that are not technically warranted for reliability reasons**	Limits interest in programs to only the most lucrative (i.e., cost effective) ones when a choice must be made between competing program options			■		
Revenue Capture	**Rules, in certain co-optimized systems, impose bidding requirements for both energy and various ancillary services**	Excludes forms of demand response and/or storage who are unable to cost-effectively provide energy for an extended length of time		■			
Revenue Capture	**Rules, in certain co-optimized systems, impose payment requirements that preclude reimbursement for energy and/or "mileage" provided by Ancillary Service resources**	Excludes forms of demand response and/or storage who are unable to cost-effectively provide such services without these payments		■			□

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Revenue Capture	**Accuracy of response to dispatch signal is not valued appropriately**	Limits demand response and/or storage resources from capturing total value provided to Balancing Authority, if fewer resources would have been required to provide bulk power system services		■			□
Revenue Capture	**Baseline forecasting of demand has high uncertainty and a lack of accuracy**	Potentially affects performance calculations thereby affecting value capture for IOU/Aggregator who must subscribe large enough resources who can more accurately produce baselines or oversubscribe aggregations of resources to manage these inaccuracies		■			
Revenue Capture	**Rules impose certain restrictions on sub-metering that are not technically warranted for reliability reasons**	Potentially reduces accuracy in baseline estimates of usage which may affect performance calculations thereby affecting value capture for IOU/Aggregator		■		□	
Program Provider	**Aggregators required to bid their demand response and storage resources participating in programs into wholesale markets via the participating customers' Load Serving Entity**	Limits Aggregators from offering such services		■			
Program Provider	**IOUs unable to differentially dispatch and pay customers on the same ancillary service program**	Precludes IOUs from offering any ancillary services programs to aggregations of demand response and/or storage resources		■			
Program Provider	**States exclude Aggregators from running their own programs, independent of the IOU**	Precludes Aggregator from offering any ancillary services programs to any form of demand response and/or storage resources		■			

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Program Provider	**State regulators do not support a third-party DR program provider model**	Precludes Aggregator from offering any ancillary services programs to any form of demand response and/or storage resources		■			
Program Provider	**Software and back-office systems to dispatch and process demand response and/or storage resources as ancillary services providers must be authorized by applicable (regulatory) authority**	Affects interest in ISO/RTO/BA and IOU to pursue demand response and/or storage resources to provide ancillary services due to risk of cost-recovery			■		
Program Provider	**Ancillary services costs are generally a pass-through to ratepayers**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services			■		
Program Provider	**Reliance on demand response and/or storage resources as ancillary service providers may reduce total sales**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services			■		
Program Provider	**Limited profit motive in short-run for pursuing demand response and/or storage resources as ancillary service providers**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services			■		
Program Provider	**Reliance on demand response and/or storage resources as ancillary service providers may reduce profits in long-run (i.e., defer need for adding new generation resources)**	Limits interest in overcoming barriers to allow demand response and/or storage resources to provide ancillary services			■		
Program Provider	**Frequency and duration of ancillary services events may exceed some customers willingness to participate**	Limits various demand response and/or storage resources from participating in ancillary services programs			■		

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Program Provider	**Complying with ancillary service event performance requirements may cause electricity bill to rise due to retail rate design (e.g., ratcheted demand charge, real-time pricing)**	Limits various demand response and/or storage resources from participating in ancillary services programs			■		
Program Provider	**Retail Energy Provider contracts in deregulated markets are too short to provide enough revenue potential to merit capital investments in DR enablement**	Limits interest in demand response, especially in enabling loads to provide more M+V intensive products			□	■	
Program Provider	**Rules impose certain financial/credit requirements (e.g., posting a bond)**	Excludes forms of demand response and/or storage who do not have the financial resources to meet met the requirements		■		□	
Program Provider	**Program administration, program compliance (e.g,. telemetry, metering) and control technology (e.g., EMCS) that are not technically warranted for reliability reasons costs to enable specific kinds of demand response and/or storage resources to comply with specific ancillary services reliability and market rules is high**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services		■		■	
Program Provider	**Benefits provided by DR and storage resources to the grid that can be captured, because externalities to the market are not reflected, are too low relative to costs to enable specific kinds of demand response and/or storage resources to comply with specific ancillary services reliability market rules**	Affects cost-effectiveness of effort to allow demand response and/or storage resources to provide ancillary services				□	■

Category	Barrier	Consequence	Change Definition	Change Requirement	Change Process	Reduce Costs	Increase Benefits
Procedural	**Market rule changes to correct observed problems with market products at Balancing Authority level must successfully navigate stakeholder working group and committee structure**	Extends the time required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services			■		
Procedural	**Regulatory change to correct observed problems with state-level DR program offerings and/or business models for such programs must successfully navigate the regulatory process**	Extends the time required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services			■		
Procedural	**Market rule changes to correct observed problems with market products at Balancing Authority level must successfully navigate stakeholder working group and committee structure**	Potentially extends the time and cost required to address identified barriers that preclude demand response and storage from effectively providing various forms of ancillary services			■		