LBNL-5063E

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Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study

Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser, Joseph H. Eto

Environmental Energy Technologies Division

October 2011

The work described in this report was funded by the Permitting, Siting and Analysis Division of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Prepared for the
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

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The authors would like to thank Larry Mansueti (DOE OE) for his support of this project. The authors would also like to thank the following individuals for providing comments and input on a review draft of this study: David Dillinger (Fraunhofer Institute), Chris King (eMeter), Michael Sullivan (Freeman, Sullivan & Company), Aaron Breidenbaugh (EnerNOC), Dale Osborn (Midwest ISO), Mark Martinez (Southern California Edison), Doug Larson (Western Governors' Association), Charlie Smith (Utility Wind Integration Group), Brendan Kirby (Consult Kirby), Kevin Porter (Exeter Associates), and Roger Levy (Levy Associates).

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Acronyms and Abbreviations

AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure
ARC	Aggregator of Retail Customers
BA	Balancing Authority
BAU	Business-as-usual
BPA	Bonneville Power Authority
C&I	Commercial and Industrial customers
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
DLC	Direct Load Control
DR	Demand Response
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
HVAC	Heating, Ventilation and Air Conditioning
I/C	Interruptible/Curtailable
IOU	Investor-Owned Utility
ISO	Independent System Operator
ISO-NE	ISO New England
LSE	Load-Serving Entity
MAE	Mean Absolute Error
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
OATT	Open Access Transmission Tariff
Open ADR	Open Automated Demand Response Protocol
PUC	Public Utility Commission
PV	Photovoltaic
RMSE	Root Mean Square Error
RTO	Regional Transmission Operator
RTP	Real-time Pricing
SPP	Southwest Power Pool
TOU	Time of Use Pricing
VG	Variable Generation
WECC	Western Electricity Coordinating Council

Executive Summary

Introduction

The penetration of renewable generation technology (e.g., wind, solar) is expected to dramatically increase in the United States during the coming years as many states are implementing policies to expand this sector through regulation and/or legislation. It is widely understood, though, that large scale deployment of certain renewable energy sources, namely wind and solar, poses system integration challenges because of its variable and often times unpredictable production characteristics (NERC, 2009).

Strategies that rely on existing thermal generation resources and improved wind and solar energy production forecasts to manage this variability are currently employed by bulk power system operators, although a host of additional options are envisioned for the near future. Demand response (DR), when properly designed, could be a viable resource for managing many of the system balancing issues associated with integrating large-scale variable generation (VG) resources (NERC, 2009). However, demand-side options would need to compete against strategies already in use or contemplated for the future to integrate larger volumes of wind and solar generation resources.

Proponents of smart grid (of which Advanced Metering Infrastructure or AMI is an integral component) assert that the technologies associated with this new investment can facilitate synergies and linkages between demand-side management and bulk power system needs. For example, smart grid proponents assert that system-wide implementation of advanced metering to mass market customers (i.e., residential and small commercial customers) as part of a smart grid deployment enables a significant increase in demand response capability.[1] Specifically, the implementation of AMI allows electricity consumption information to be captured, stored and utilized at a highly granular level (e.g., 15-60 minute intervals in most cases) and provides an opportunity for utilities and public policymakers to more fully engage electricity customers in better managing their own usage through time-based rates and near-real time feedback to customers on their usage patterns while also potentially improving the management of the bulk power system.

At present, development of time-based rates and demand response programs and the installation of variable generation resources are moving forward largely independent of each other in state and regional regulatory and policy forums and without much regard to the complementary nature of their operational characteristics.[2] By 2020, the electric power sector is expected to add ~65 million advanced meters[3] (which would reach ~47% of U.S. households) as part of smart grid

[1] Most utilities have already installed interval meters for their medium to large commercial and industrial customers.
[2] Many states that have implemented a renewable portfolio standard are not heavily promoting demand response resources in lockstep as a means to mitigate the integration issues associated with increased levels of variable generation. Furthermore, at present, demand response opportunities are not being designed to or vigorously pursued which enable access to customer response that could specifically address variable generation integration issues.
[3] FERC (2006) defines advanced metering as a "a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

and AMI[4] deployments (IEE, 2010) and add ~40-80 GW of wind and solar capacity (EIA, 2010). Thus, in this scoping study, we focus on a key question posed by policymakers: what role can the smart grid (and its associated enabling technology) play over the next 5-10 years in helping to integrate greater penetration of variable generation resources by providing mass market customers with greater access to demand response opportunities?

There is a well-established body of research that examines variable generation integration issues as well as demand response potential, but the nexus between the two has been somewhat neglected by the industry. The studies that have been conducted are informative concerning what could be accomplished with strong broad-based support for the expansion of demand response opportunities, but typically do not discuss the many barriers that stand in the way of reaching this potential. This study examines how demand side resources could be used to integrate wind and solar resources in the bulk power system, identifies barriers that currently limit the use of demand side strategies, and suggests several factors that should be considered in assessing alternative strategies that can be employed to integrate wind and solar resources in the bulk power system.

It is difficult to properly gauge the role that DR could play in managing VG integration issues in the near future without acknowledging and understanding the entities and institutions that govern the interactions between variable generation and mass market customers (see Figure ES-1). Retail entities, like load-serving entities (LSE) and aggregators of retail customers (ARC), harness the demand response opportunities of mass market customers through tariffs (and DR programs) that are approved by state regulatory agencies or local governing entities (in the case of public power). The changes in electricity consumption induced by DR as well as the changes in electricity production due to the variable nature of wind and solar generation technologies is jointly managed by bulk power system operators. Bulk power system operators function under tariffs approved by the Federal Energy Regulatory Commission (FERC) and must operate their systems in accordance with rules set by regional reliability councils. These reliability rules are derived from enforceable standards that are set by the North American Electric Reliability Corporation (NERC) and approved by federal regulators. Thus, the role that DR can play in managing VG integration issues is contingent on what opportunities state and local regulators are willing to approve and how customers' response to the DR opportunities can be integrated into the bulk power system both electrically (due to reliability rules) and financially (due to market rules).

[4] The U.S. Government invested $3.5 billion under the American Recovery and Reinvestment Act in the Smart Grid Investment Grant program; 74 grantees proposed spending ~$2.2 billion on AMI investments (DOE, 2011).

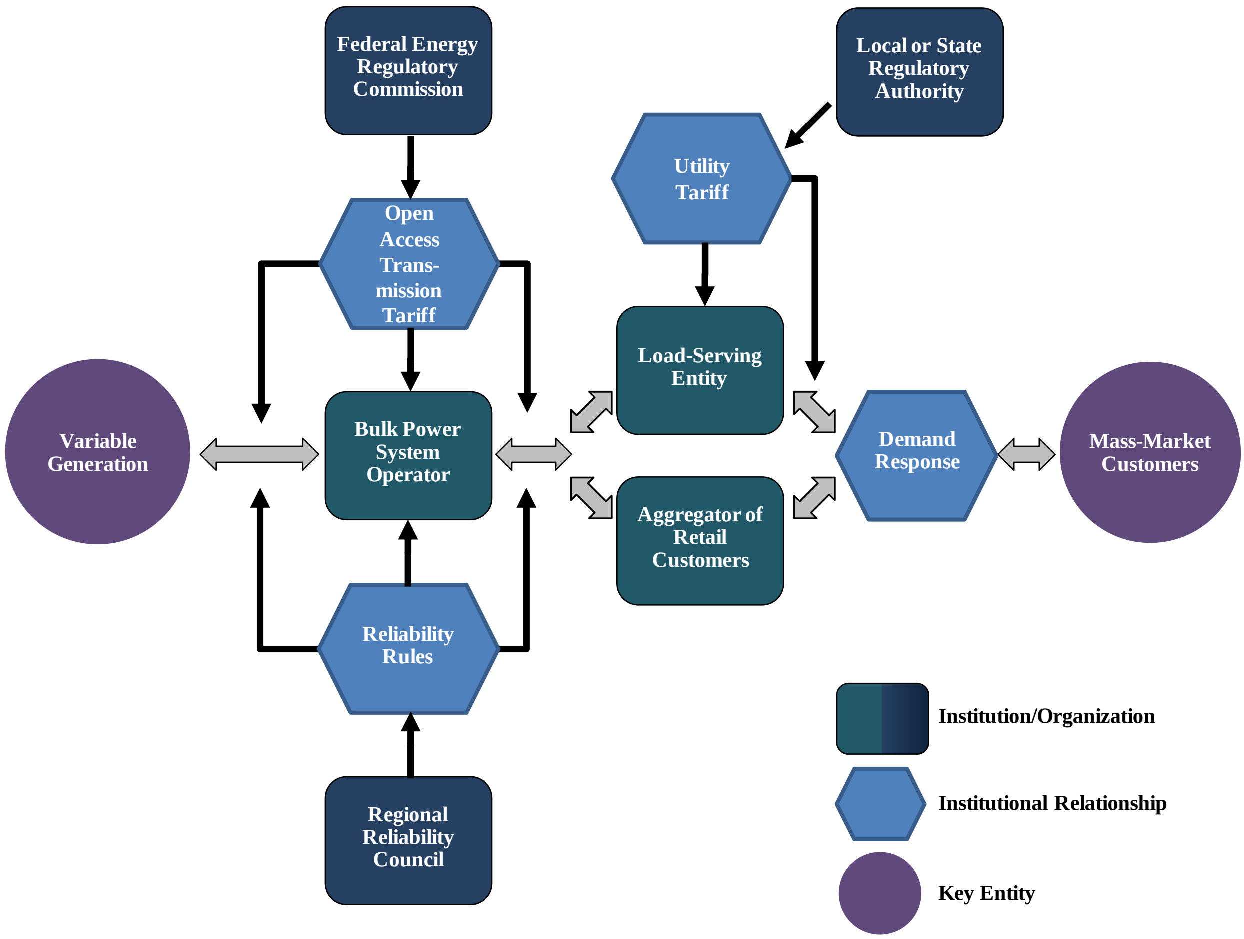


Figure ES-1. Organizations and institutions that influence relationship between VG and DR resources

Objectives and Scope

To complement this existing literature and to identify areas where future research and/or policy enhancements may be needed, we will[5]:

- Identify key issues associated with integrating large amounts of variable generation into the bulk power system;
- Identify demand response opportunities made more readily available to mass market customers through widespread deployment of AMI systems and how they could affect the bulk power system;
- Assess the extent to which these mass market DR opportunities could manage VG integration issues in the near-term and what electricity market structures and regulatory practices could be changed to further expand the ability for DR to manage VG integration issues over the long term; and

[5] This scoping study focuses primarily on policy issues that must be resolved for demand response to manage variable generation integration issues. We do not assess the potential role of specific technologies (e.g., microgrids, plug-in electric vehicles, battery storage) or standards (e.g., OpenADR) to address these issues.

- Provide a qualitative comparison of proposed and existing strategies to manage VG integration issues relative to DR opportunities.

Findings

1. **The largest variability and uncertainty in variable generation power production is over time periods of 1 to12 hours; time scales that are in synch with the operation of most demand response opportunities for mass market customers.**

   The deployment of advanced meters and two-way communications networks between customers and the utility driven by the rollout of Advanced Metering Infrastructure and smart grid will greatly increase demand response opportunities available to mass market customers. This group of customers likely represents the most significant untapped potential DR resource in the United States (FERC, 2009a).

2. **Highly variable time-based retail rates (i.e., real-time pricing) coupled with automation/control technology has significant technical potential for managing various variable generation integration issues, although the current lack of regulatory and stakeholder support is a key challenge.**

   Among time-based rates, hourly real-time pricing, in conjunction with customer automation and controls, has the greatest potential to address variable generation integration issues (see Table ES-1). However, at present, there appears to be little regulatory and stakeholder support for transitioning mass market customers onto RTP rates. Utilities in only one state (Illinois) currently offer these tariffs to residential customers. State regulators and stakeholders are more receptive to introducing CPP or CPR as voluntary (opt-in) time-based rates in conjunction with their deployment of AMI. However, CPP and CPR have limited potential to address variable generation integration issues (see Table ES-1). In the future, if such rate designs are made more flexible in terms of event duration, advanced notification, level of the DR signal and are coupled with some form of automation or control technology, they could be more valuable to bulk power systems dealing with high penetrations of variable generation resources. Moreover, consumer advocates (AARP et al., 2010) have raised concerns about the impacts of time-based rates on "at-risk" groups (e.g., customers with medical conditions, the elderly and poor). Several recent studies have looked at the response of low-income customers to various types of time-based rates (e.g., eMeter Strategic Consulting, 2010; Faruqui and Sergici, 2010), although more definitive and consistent evidence will likely be required from future studies to address concerns raised by these stakeholders.

Variable Generation Integration Issues	TOU	CPR	CPP	DA-RTP	RT-RTP
1 min. to 5-10 min. variability					
<2 hr. forecast error					○
Large multiple hour ramps					○
>24 hr. forecast error					○
Variation from average daily energy profile		◎	◎	○	○
Average daily energy profile by season	◎			○	○

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◎	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table ES-1. LBNL assessment of the ability of time-based retail rates to address variable generation integration issues

3. **Incentive-based DR programs have significant potential to manage many variable generation integration issues if residential customers are willing to participate in programs whose designs feature short duration and frequent demand response events. Program designs that allow load aggregators to participate effectively and customer acceptance of control and/or automation technology are key factors that will determine the efficacy of these DR programs in managing variable generation integration issues.**

    Mass market customers subscribing to most incentive-based DR programs will need to increasingly rely on control and automation technology to provide demand response over shorter time durations and more frequent changes in the DR signal (see Table ES- 2). Ratepayer skepticism about accepting end-use control technology will have to be overcome with thoughtful marketing and education efforts if these programs are to attain widespread participation levels. In many respects, customer acceptance of these DR opportunities is intertwined with their acceptance of control and automation technology. To properly prepare customers with response capabilities, technology implementation will likely have to run in parallel with or actually precede actual rate and program implementation, such that customers will have already established price/event response strategies and then may use their control/automation technology to "set it and forget it". Over the longer term, policymakers and regulators may need to re-think the regulatory and market design context for facilitating demand response opportunities among mass market customers. Utility load management programs have long bundled incentives and automation/control technology. Such an approach tends to address market segments targeted at specific end uses (e.g., air conditioning). Given advances in control, information and communication technology, it is not certain that this bundled program design approach is optimal going forward as it is now much more feasible to target multiple end uses (e.g., appliances, HVAC equipment, plug loads) and thus a more diverse set of mass market customers. Over the long term, this bundled approach may also constrain the development of vibrant markets for smart appliances, innovative automation options, and new energy services that include a large number of service providers. An alternative, more unbundled approach that should be considered would encourage utilities to create an infrastructure that provides customers with price/event signals and financial incentives and then encourage ARCs and other energy service vendors to offer and support automation/control equipment and demand response services as part of a competitive market.

Variable Generation Integration Issues	DLC	Emergency DR	Capacity	Energy	Ancillary Services
1 min. to 5-10 min. variability	○				○
<2 hr. forecast error	◉	○		○	○
Large multiple hour ramps	◉			○	
>24 hr. forecast error	○			○	
Variation from average daily energy profile		○	○	○	
Average daily energy profile by season					

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◉	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table ES- 2. LBNL assessment of the ability of incentive-based DR programs to address variable generation integration issues

4. **Accessing the diversity and flexibility of customer demand to facilitate integration of large-scale variable generation is likely to require additional changes in market rules and regulatory policies.**

   Many jurisdictions may need to consider modifying existing retail market tariffs so that utilities or ARCs can treat customers as a portfolio of resources that can be differentially dispatched. Similarly, changes to reliability rules should be considered that allow ARCs (or very large customers) the ability to provide the full range of bulk power system services. Finally, wholesale market product definitions may need to be expanded and/or market operations may need to be restructured to allow DR to offer and be paid for providing these services.

5. **System operators and policymakers should systematically analyze the perceived risks, costs and benefits of the various strategies, including demand response, to facilitate the integration of large-scale VG resources.**

   As variable generation resources have increased in the U.S., system operators and policymakers are considering a wide range of strategies to integrate large-scale variable generation in addition to demand response, including: (1) improved forecasting tools to increase accuracy of expected output from variable generators, (2) technology improvements in variable generation that enable these resources to provide some bulk power system services, (3) investing to increase the transmission capacity of the bulk power system, (4) implementing changes in the operating structure of the bulk power system (e.g. larger balancing authorities) or (5) instituting changes to existing wholesale power market design (e.g., intra-hour markets in the West). Determining the relative attractiveness of and mix of alternative strategies to manage particular VG integration issues requires estimating and comparing the balancing, resource adequacy, and ramping costs, system benefits, and perceived risks for all eligible resources. For example, the benefit of a demand response program that could provide balancing services comparable to thermal generators would include the reduction in system costs from not requiring thermal generators to provide the additional balancing service. Results from the Western Wind and Solar Integration Study (GE Energy, 2010) illustrate boundary conditions where DR may be a cost-effective alternative to mitigate a particular VG integration issue. They estimated that the benefits of using demand response instead of spinning reserves from thermal generators would be on the order of $310-450/kW-yr for a DR resource that would provide load reductions with little or no notice for 10-35 hours per year (on average) and could be called on any time of day or season. These kinds of determinations will vary by system operating characteristics, generation mix, load and a host of other dynamics that make generalization difficult and should be an area of future research.

Next Steps

In order for time-based rates and incentive-based DR program to play a significant role in helping to integrate widespread deployment of variable generation, it will require regulatory and stakeholder acceptance and support for RTP, policies that support widespread deployment of home and appliance automation and control technologies, market rules that allow customer loads to provide ancillary services that recognize distinctive features of customer loads, evidence that various demand response resources can provide comparable bulk power services to facilitate integration of wind and solar generation resources, and regulatory and market policies that encourage load aggregators to participate effectively in wholesale and retail electricity markets.

The value generated from demand response resources in managing variable generation integration issues will likely be just one of many benefits streams used to justify the investment in AMI and smart grid technology. The greater the number of opportunities for DR to provide value, the more likely it will be that utilities and end-users insist that policymakers adopt the necessary changes to facilitate an expansion in the offering and adoption of demand response opportunities. More still needs to be understood about what will sufficiently motivate mass market customers to participate in these different types of demand response opportunities and the control/automation technologies they may require, especially those that in managing variable generation integration produce a DR signal that changes frequently and potentially unexpectedly. This is clearly an area for further research.

1. Introduction

The penetration of renewable generation technology (e.g., wind, solar, biopower, geothermal) is expected to dramatically increase in the United States over the coming years as many states are implementing policies to expand this sector through regulation and/or legislation. Twenty-nine states and the District of Columbia have established binding targets for the procurement of renewable energy in the power sector while another seven states have established voluntary goals through legislation (Wiser et al., 2010). It is widely understood, though, that large scale deployment of certain renewable energy sources (i.e., wind and solar), because of its variable and often times unpredictable production characteristics, poses integration challenges for bulk power system operators (NERC, 2009).[6]

Bulk power system operators currently rely primarily on thermal generation resources and improved wind and solar energy production forecasts to manage the variability of wind and solar resources; several additional options are envisioned for the near future. Demand response (DR), when properly designed, could be a viable resource for managing many of the system balancing problems associated with integrating large-scale variable generation (VG) resources (NERC, 2009), provided that DR can compete against the measures already in use to integrate wind and solar. Yet, maximizing demand response opportunities are often times limited by, among other things, infrastructure. For example, a lack of interval metering, control technology, and availability of low-cost telemetry and communications networks seriously hinders a utility's ability to offer demand response rates and programs to its mass market customers. However, over the past ten years, the costs of advanced interval meters, the communications networks to connect the meter with the utility, and the back-office systems necessary to maintain and support them (collectively referred to as Advanced Metering Infrastructure or AMI) have all come down (in some cases dramatically). Proponents of smart grid (of which AMI is an integral component) assert that these technologies can facilitate synergies and linkages between demand-side management and bulk power system needs. For example, smart grid proponents assert that system-wide implementation of advanced metering to mass market customers (i.e., residential and small commercial customers) as part of a smart grid deployment enables a significant increase in demand response capability.[7] Specifically, the implementation of AMI allows electricity consumption information to be captured, stored and utilized at a highly granular level (e.g., 15-60 minute intervals in most cases) and provides an opportunity for utilities and public policymakers to more fully engage electricity customers in better managing their own usage through time-based rates and near-real time feedback to customers on their usage patterns while also potentially improving the management of the bulk power system.

At present, development of demand response rates and programs and the installation of variable generation resources are moving forward largely independent of each other in state and regional regulatory and policy forums and without much regard to the complementary nature of their

[6] Other renewable generation technologies, including biopower and geothermal do not present many of the same grid integration challenges. Waterpower technologies (e.g., ocean and hydrokinetic) do have variable output and therefore may not significantly contribute to resource adequacy. Waterpower technologies may also have significant ramps in output due to changing tides or ocean currents, but these changes are regular and predictable. Additional analysis of the challenges in integrating waterpower vs. wind and solar resources are available in IPCC (2011).

[7] In contrast, in most jurisdictions, interval meters are already installed and utilized by medium and large commercial and industrial customers.

operational characteristics.[8] By 2020, the electric power sector is expected to add ~65 million advanced meters[9] (which would reach ~47% of U.S. households) as part of smart grid and AMI[10] deployments (IEE, 2010), and add ~40-80 GW of wind and solar capacity over the next decade (EIA, 2010). Thus, this study examines how demand side resources could be used to integrate wind and solar resources in the bulk power system and identifies barriers that currently limit the use of demand side strategies.

There is a well-established body of research that examines variable generation integration issues as well as demand response potential, but the comparative assessment of the two has been somewhat neglected by the industry (see Table 1). To date, there have been at least 12 studies that focus exclusively on how demand response opportunities can help manage specific variable generation integration issues that affect the bulk power system. These studies are highly informative concerning what could be accomplished with strong broad-based support for the expansion of demand response opportunities, but typically do not discuss the many barriers that stand in the way of reaching this potential. As Table 1 illustrates, each of the 12 studies tends to focus on a limited set of demand response opportunities and covers only a subset of the broad range of potential variable generation integration issues. For example, Callway (2009) focuses exclusively on the role that DR programs targeted at ancillary services markets can play in affecting shorter-term VG integration issues. Sioshansi and Short (2009) assess the role of real-time RTP in managing variable generation integration issues that occur over longer term horizons (e.g., day-ahead forecast errors and variations in average daily energy profile). Most studies utilize numerical simulation techniques to illustrate the potential of demand response to manage very specific variable generation issues and often include ambitious assumptions about the DR opportunities under review. For example, several studies (e.g., Denholm and Margolis, 2007; Stadler, 2008; Sioshansi and Short, 2009; Klobasa, 2010; Moura and de Almeida, 2010; Roscoe and Ault, 2010) incorporate demand response opportunities that are not highly supported by state regulators and policymakers in the U.S, like exposing customers to prices that change every hour or more frequently with little to no advance notice of pricing changes (i.e., real-time RTP). Alternatively, several other studies (e.g., Lund and Kempton, 2008; Papavasiliou and Oren, 2008; Callaway, 2009; GE Energy, 2010; Hughes, 2010; Kondoh, 2010) assume wide-spread customer adoption of control technology (e.g., large scale replacement of appliances with "smart" refrigerators, freezers, dryers) at levels that are likely to be unrealistic over the next 5-10 years.

[8] Many states that have implemented a renewable portfolio standard are not heavily promoting demand response in lockstep as a means to mitigate the integration issues associated with increased levels of variable generation. Furthermore, at present, demand response opportunities are not being designed to or vigorously pursued which enable access to customer response that could specifically address variable generation integration issues.

[9] FERC (2006) defines advanced metering as a "a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

[10] The U.S. Government invested $3.5 billion under the American Recovery and Reinvestment Act in the Smart Grid Investment Grant program; 74 grantees proposed spending ~$2.2 billion on AMI investments (DOE, 2011).

Variable Generation Integration Issue	Demand Response Opportunities			
	Ancillary Services	Direct Load Control	Day-Ahead RTP	Real-Time RTP
1 Min. to 5-10 Min. Variability	1, 6	9		
<2 Hr. Forecast Error	1	9		5
Large Multi-hour Ramps	1	8		5, 11
>24 Hr. Forecast Error	3			5, 11
Variations in Avg. Daily Energy Profile		4, 7	2, 8, 10	11, 12
Avg. Daily Energy Profile by Season		4, 7	2, 8, 10	11, 12

1	Callaway, 2009	7	Lund and Kempton, 2008
2	Denholm and Margolis, 2007	8	Moura and de Almeida, 2010
3	GE Energy, 2010	9	Papavasiliou and Oren, 2009
4	Hughes, 2010	10	Roscoe and Ault, 2010
5	Klobasa, 2010	11	Sioshansi and Short, 2009
6	Kondoh, 2010	12	Stadler, 2008

Table 1. Demand response and variable generation integration issues examined in existing studies

One of the key issues that is not well addressed in the existing studies on the role that smart grid (and AMI) can play in managing variable generation integration issues is an analysis and assessment of the entities and institutions that govern the interactions between variable generation and mass market customers with DR potential (see Figure 1). Retail entities, specifically load-serving entities (LSE) and aggregators of retail customers (ARC), harness the demand response opportunities (i.e., rates and programs) of mass market customers through tariffs (and DR programs) that are approved by state regulatory agencies or local governing entities (in the case of public power). The changes in electricity consumption induced by time-based rates and incentive-based DR programs as well as the changes in electricity production due to the variable nature of wind and solar technologies is jointly managed by bulk power system operators. Bulk power system operators function under tariffs approved by the Federal Energy Regulatory Commission (FERC) and must operate their systems in accordance with rules set by regional reliability councils. These reliability rules are derived from enforceable standards that are set by the North American Electric Reliability Corporation (NERC) and approved by federal regulators. Thus, the role that DR can play in managing VG integration issues is contingent on what opportunities state and local regulators are willing to approve and how customers' response to the DR opportunities can be integrated into the bulk power system both electrically (due to reliability rules) and financially (due to market rules).

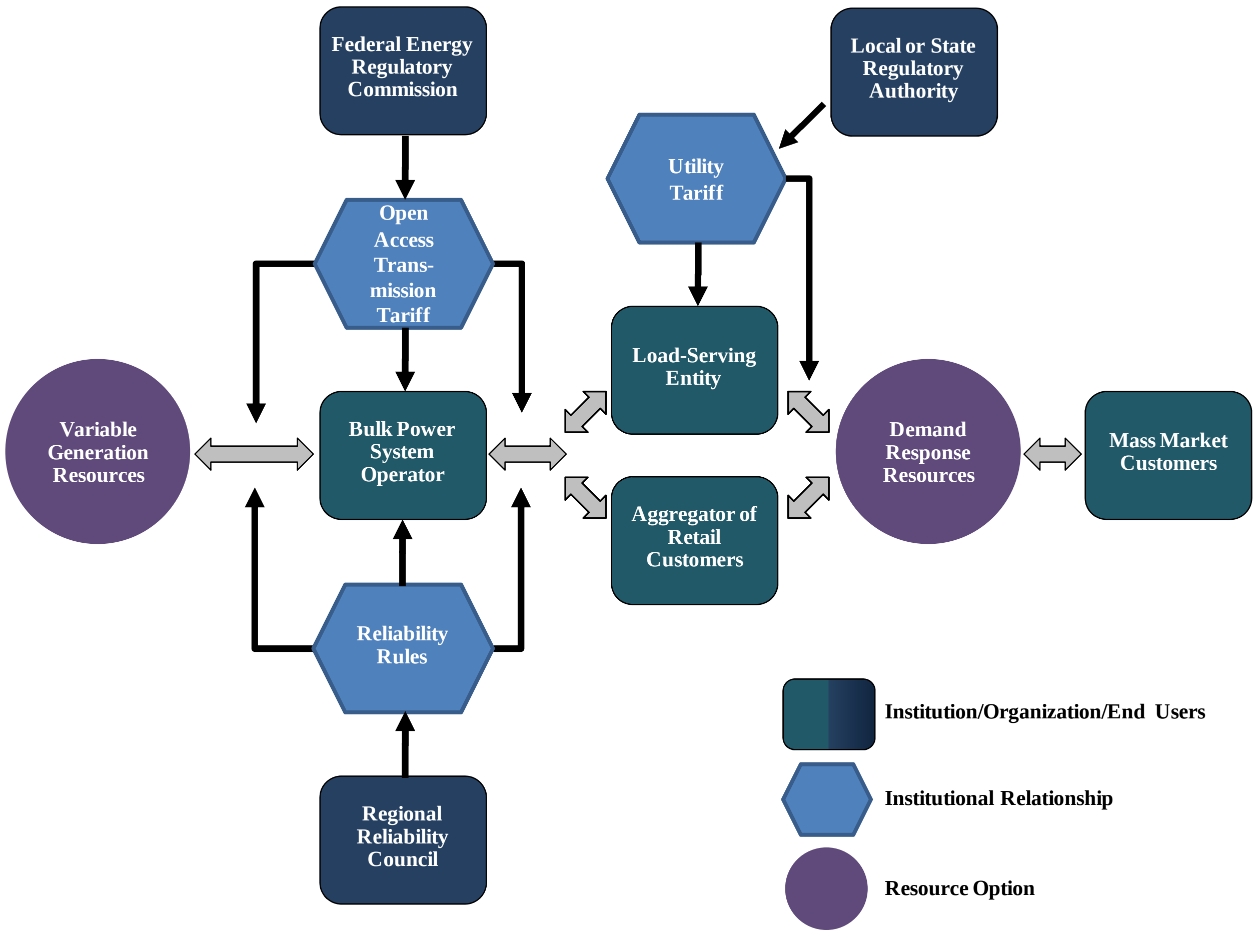


Figure 1. Organizations and institutions that influence relationship between VG and DR resources

To complement this existing literature and to identify areas of need for future research and/or policy design, this scoping study focuses on the policy issues inherent in the claims made by some smart grid proponents that mass-market level demand response enabled by widespread implementation of AMI through the smart grid could be the "silver bullet" for managing variable generation integration issues. A primary finding of this scoping study is that changes will be required in many of the institutional principles and relationships that currently govern the interactions between mass market customers, retail entities offering demand response opportunities, and bulk power system operators in order for these demand response resources to manage variable generation integration issues (see Figure 1).[11] To do so, this scoping study will:

- Identify key issues associated with integrating large amounts of variable generation into the bulk power system;
- Identify demand response opportunities made more readily available to mass market customers through widespread deployment of AMI systems and how they could affect the bulk power system;

[11] This scoping study focuses primarily on policy issues that must be resolved for demand response to mitigate variable generation integration issues. We do not assess the potential role of specific technologies (e.g., microgrids, plug-in electric vehicles, battery storage) or standards (e.g., OpenADR) to address these issues.

- Assess the extent to which these mass market DR opportunities could manage VG integration issues in the near-term and what electricity market structures and regulatory practices could be changed to further expand the ability for DR to manage VG integration issues over the long term; and
- Provide a qualitative comparison of demand-side opportunities compared to other strategies and approaches that are currently utilized or are being considered in the near future to manage VG integration issues.

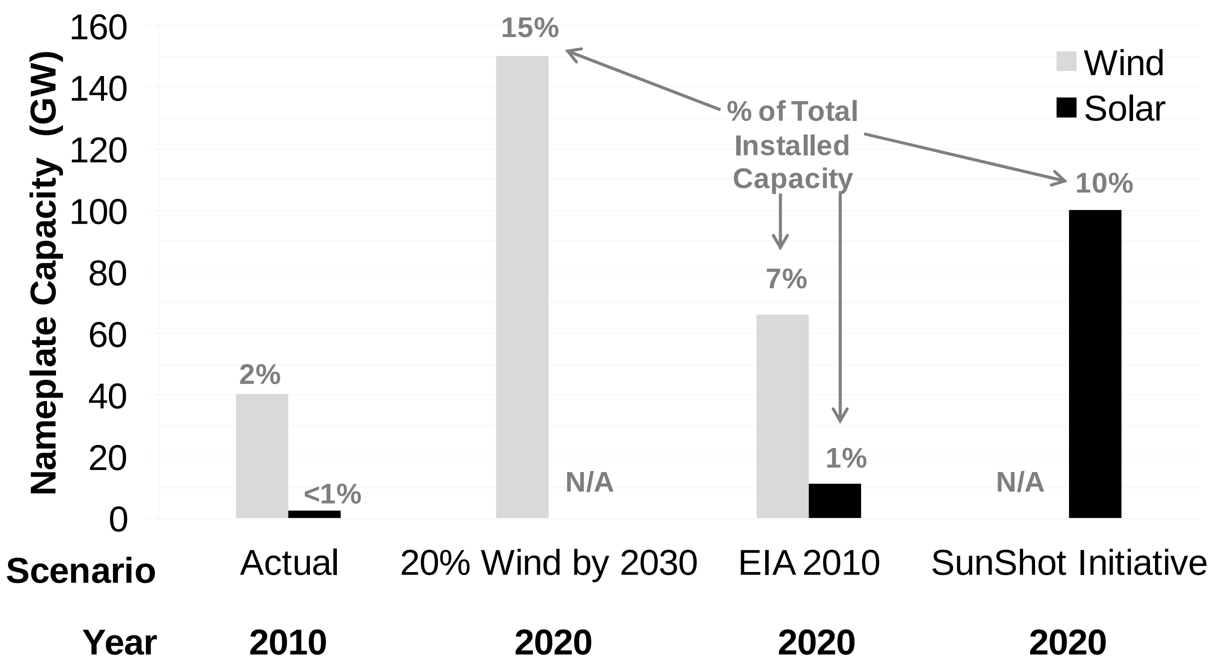
This study is organized as follows. In Section 2, we identify and briefly describe the major attributes of variable generation resources across multiple relevant time scales and how these operational characteristics affect bulk power system operations. In Section 3, we characterize the current generation of demand response opportunities available to smaller (i.e., mass market) customers, the time scales over which these rates/programs are expected to produce changes in the electricity consumption of end-use customers and how such changes could be harnessed to provide bulk power system services. In Section 4, we examine which demand response opportunities are most consistent with each of the previously identified variable generation integration issues, identify institutional or market barriers that if changed could expand DR opportunities, and compare proposed and existing non-DR and DR strategies for integrating large scale variable generation in bulk power systems. In Section 5, we summarize conclusions from this scoping study and identify areas for future research.

2. Variable Generation Resources and the Bulk Power System

2.1 Overview:

The impact of wind and solar generation resources on the bulk power system depends both on the scale and operational characteristics of these variable generation technologies and the way that the bulk power system is planned and operated. This section identifies and briefly describes the major attributes of variable generation across multiple relevant time scales. The characteristics of variable generation will then be evaluated in the context of the operation of the bulk power system. In particular, this section identifies how characteristics of variable generation map onto the operation of the bulk power system and highlights areas where variable generation introduces particular challenges.

2.2 Projections of Near-Term Growth in Variable Generation



Sources: 2010 Capacity: Solar – Solar Energy Industries Association (2011), Wind – Wiser and Bollinger (2011); 2020 Capacity: 20% Wind by 2030 (DOE, 2008), EIA (2010), SunShot Initiative (DOE, 2010).

Figure 2. Growth projections for variable generation resources

As of the end of 2010, 40 GW of wind and 2.6 GW of solar were installed in the U.S. In terms of energy, wind provided 2.3% and solar provided less than 0.1% of the annual electricity generated in the U.S., respectively (see Figure 2). However, these variable generation technologies have matured rapidly over the past decade and near term (2020) scenarios indicate 80-160 GW of VG in a future U.S. power system that has >990 GW of total installed generation.

The 2020 scenarios lead to less than 20% wind and solar on a capacity basis on a national average, but individual regions within the U.S. are expected to see much greater penetrations of VG as a percentage of peak generation.

2.3 Characteristics of Variable Generation

The electrical generation characteristics of VG are strongly weather dependent. The generation output varies with seasonal, diurnal, and synoptic weather patterns that are not always regular or predictable. However, decades of industry experience with operating variable power plants has shown that there are particular characteristics that are similar across sites and regions. These characteristics vary with time scale and the level of aggregation of VG. For the purpose of this study, we assume that VG interacts with the bulk power system and that high penetration levels are expected. At high levels of penetration, the electrical generation from multiple diverse VG sites is aggregated at the bulk power system level, which tends to smooth the aggregate variability and uncertainty for shorter time scales, relative to what would be expected from scaling up a single VG site.

Table 2 provides a summary of the different variable generation production characteristics as the time scale increases from seconds to years.[12] While variable generation introduces additional variability and uncertainty over short-time scales (minutes), the magnitude of variability and uncertainty of the aggregate of several VG resources tends to be smaller than the magnitude over longer time scales (i.e., multiple hours and longer). In this case, the magnitude of variability and uncertainty of variable generation is represented by the change in power production or magnitude of forecast errors over particular time scales as a percentage of the variable generation nameplate capacity. For example, over very short time scales (i.e., less than one minute), the aggregate variability of wind plants has been measured at less than 0.2% of the nameplate capacity of the wind plants (Wan, 2005). Less high time-resolution data is available for aggregated solar plants, but smoothing of 10-sec variability even within a single 13.2 MW PV plant suggests that the aggregate variability of high penetrations of PV over very short times scales will also be low (Mills et al., 2009; Mills and Wiser, 2010; Marcos et al., 2011). Due to the relatively low variability for many sites aggregated at the bulk power system level, we do not address very short time scale variability in the remainder of this scoping study.

Over the time scale of about five to ten minutes, the variability of aggregated wind (Wan, 2005) and solar plants (Wiemken et al., 2001; Mills and Wiser, 2010) is still only a small fraction of the name plate capacity, but rare events can lead to significant changes in aggregate plant output. Short-term forecasts of VG over the next ten to 120 minutes are used in integrating VG into the bulk power system. For example, in one study, the worst hour-ahead forecast error reported for wind was ~24% of the installed capacity (GE Energy, 2005). The aggregation of short-term forecasts does significantly reduce forecast errors relative to individual sites for both wind and solar. Wind and solar forecasts of the expected hourly production for a forecast horizon of multiple hours to multiple days are less accurate than very short-term forecasts.

[12] Table 2 presents a summary of statistics for wind from a wide variety of sources and geographic regions. Actual variability will depend on the geographic region, the placement of wind plants, and the amount of wind being analyzed. See Appendix A for a more detailed discussion of characteristics of variable generation.

Aside from incorrect forecasts, it is particularly challenging to manage changes in the output of wind that are sustained for multiple hours. These multiple hour ramps can be triggered by large weather systems or fronts moving through a region or due to diurnal weather patterns (i.e., cold ocean air moving into hot desert regions during the day and vice versa at night). In the case of weather fronts, the sustained ramps can often be forecast to pass through a region days ahead of time, but the exact timing of the frontal passage within the day is difficult to predict until a few hours prior to the event (Greaves et al., 2009). For example, extreme six hour ramps modeled from 15 GW of wind energy in the regions near Tehachapi, California or the Columbia Gorge in Washington are 65-85% of the wind nameplate capacity. Ramps of these magnitudes or greater would occur less than about 5-10 times per year (see Appendix A). Wind energy resources in both of these regions are geographically concentrated and will tend to show more extreme ramps than would be expected from more geographically dispersed wind resources. For example, large multiple hour ramps measured from nearly 9 GW of wind in ERCOT indicated that the largest sustained ramp was just over 50% of the nameplate capacity over a period of more than 12 hours (Wan, 2011).

On a longer term basis, system planners and operators need to contend with production profiles that, on average, vary substantially throughout the course of the day and then vary again at a seasonal level. The average daily profile of solar resources over a specific season will change from zero at night to maximum around noon and back to zero at night, while wind resources may have a diurnal profile but it will not be as dramatic and regular. The solar resource is strongest in the summer months. However, due to inefficiencies with increasing ambient temperatures for both PV and solar thermal plants, the greatest net solar production can occur in spring and fall seasons. Similar seasonal differences are observed for wind energy as well. For example, the average wind production estimated for the WestConnect footprint is 15% of the nameplate capacity of wind greater in the spring months compared to summer months (GE Energy, 2010).

Variable Generation Production Characteristics	Abbreviated Name	Example of Wind Variability (% of Nameplate Capacity)
Changes in output over very short time scales	<1-minute variability	0.1%-0.2%
Changes in output over short time scales	1 minute to 5-10 minute variability	3-14%
Imperfect ability to forecast generation output for time horizon of 10-120 minutes	<2 hour forecast error	3-25%
Changes in a single direction for multiple hour periods	Large multiple hour ramps	50-85%
Imperfect ability to forecast generation output for time horizon of multiple hours to days ahead	>24 hour forecast error	6-30%
Deviations from the average daily generation profile in actual day to day generation	Variation from average daily energy profile	25-60%
Average daily energy profile generation characteristics depending on the season	Average daily energy profile by season	30-50%

Table 2. Variable generation production typology

2.4 Integration into the Bulk Power System

The variability and uncertainty of VG over different time scales will impact different aspects of bulk power system operations (see Table 2). The bulk power system consists of the major load centers, transmission lines, and generation assets in a region. The power system is operated to securely maintain a balance between the aggregate load and aggregate generation. Secure operation means that the power system is operated in a way that it can recover from major contingencies without blackouts. A key aspect of power systems is that aggregation of multiple loads and generators increases reliability and reduces operational costs. Bulk power system *operations* focus on time scales from the very short (i.e., sub-minute balancing) to multiple days ahead for scheduling purposes.[13] The power system must also be able to accommodate changes in the characteristics of generation and load over even longer seasonal time scales.

Table 3 shows the different bulk power system operations that have been posited will be affected by substantially increased penetration of variable generation resources.[14] Reliability standards require power system operators to maintain operating reserves that can be deployed in the event of a contingency. Operating reserves are characterized by the time required to be fully deployed and the duration of the response. *Spinning reserves* (or secondary response) resources must be able to automatically respond to a control signal sent by the system operator (usually the Automatic Generation Control or AGC) in less than ten seconds and to provide response for roughly 30 minutes. *Supplemental reserves* (or tertiary response) resources are able to respond to short notice dispatch instructions from the system operator in ten to 30 minutes. In addition to reserves required to respond to infrequent contingencies, system operators procure *regulating reserves* to continuously maintain a balance between load and supply during normal operations. Regulation reserves are required to manage most deviations from dispatched generation and load in between dispatch periods (~five minutes to one hour, depending on the market).

Whereas regulation reserves are controlled using automatic generation control signals, regular dispatch schedules are used to change the output of generation over longer periods. The resources that are dispatched by system operators to manage deviations between load and generation every five to 15 minutes, depending upon dispatch period, within an operating hour are called the *load following* resources. Schedules for load and generation are also provided further out in time: at least 60 minutes ahead of the operating hour and also on a day-ahead basis to match near-term and longer-term forecasts (respectively) of load with supply schedules. Resources that are called on to change their output in response to errors in schedules provide what is called *imbalance energy* in some regions and supplemental energy in others.

Changes in demand for hour-ahead and imbalance energy in the same direction for long periods (e.g., the morning load pick-up) require adequate *ramping capability* of the dispatchable generation in the market and the supplemental energy stack. Insufficient ramping capability will

[13] Due to the short-time scales associated with voltage balancing and power quality and the difficulty for demand response resources to provide this service, we will not include these ancillary services in the discussion hereafter although we recognize that VG can affect these bulk power system operations (NERC, 2009).
[14] See Appendix B for a more detailed discussion of the issues associated with integrating large amounts of variable generation into the bulk power system.

lead to deployment of reserves to provide energy or load shedding. If markets cannot clear due to insufficient demand to absorb the generation or system operators cannot dispatch load-following resources to a lower level due to minimum generation constraints and/or transmission constraints, then out-of-market actions may be required to maintain balanced operation. This condition is known as *over-generation* and can be addressed by de-committing units, curtailing generation output, or increasing demand. Planners must also look multiple years into the future to ensure that sufficient flexible demand or generation capacity exists to meet future electricity requirements – a process known as *resource adequacy*.

	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 ahead	<1 min	~1 min	~30 min	~20-200 times per year
Supplemental Reserves (Contingency)	Days ahead	<10 min	~10-30 min	~Multiple hours	~20-200 times per year
Regulation Reserves (Normal Operation)	Days to hours ahead	~1 min to 10 min	None	< 10-min in one direction	Continuous
Load Following/ Imbalance Energy	5 min to 1 hr	5 min to 1 hr	5 min to 1 hr	5 min to 1 hr	Depends on position in bid stack
Hour-ahead Energy	1-2 hrs	5 min to 1 hr	1-2 hrs	>1 hr	Depends on position in bid stack
Multi-hour Ramping Capability	None	5 min to 1 hr	Days ahead to 30 min	1-4 hrs	As frequent as daily
Day-ahead Energy	24-36 hrs	1 hr	24-36 hrs	>1 hr	Depends on position in bid stack
Over-generation	None	1 hr	Days to multiple hrs ahead	1 to multiple hrs	Seasonal
Resource Adequacy	Years	1 hr	Day ahead	Multiple hrs	Seasonal

Table 3. Bulk power system operations affected by large-scale deployment of variable generation

2.5 FERC-Approved Tariffs

The bulk power system in the U.S. operates under a regime of open access, meaning that the bulk power system cannot unduly restrict generators and loads from using the transmission system to trade electricity.

In regions without organized markets, bilateral trades occur between loads and generators and balancing authorities facilitate these trades into, out of, or across their balancing area.

Depending on the region, schedules for the trades are typically set prior to or during the hour ahead of the actual operating hour. Balancing areas file open access transmission tariffs (OATT) with the Federal Energy Regulatory Commission (FERC) that allow the balancing areas to charge users for the ancillary services provided by the balancing area to facilitate these trades. The pro-forma open access tariff includes a charge for ancillary services including operating reserves, regulation and frequency response services, and imbalance energy. On a case-by-case basis, FERC approves modifications to the OATT that change the allocation of the cost of ancillary services. For example, Westar Energy was recently allowed to charge a higher regulation and frequency response services charge to wind that is being exported to other balancing areas than other generation resources. In contrast, Entergy charges for regulation services based on the generators largest 10-min deviation from the hourly schedule. Larger deviations lead to higher regulation charges. In all cases, customers can choose to self-supply these ancillary services by placing a resource that can provide the required ancillary services under the operational control of the system operator rather than pay the FERC-approved tariff. For example, a wind generator could partner with a hydro facility or demand response aggregator to provide the regulation and imbalance energy for the wind plant rather than pay the charge outlined in the OATT.

Currently, in regions without organized wholesale markets, OATTs do not address issues around unit commitment, day-ahead forecast errors, and multiple hour ramping capability. For example, the OATT does not charge for or prevent a wind generator from submitting hour-ahead schedules with large hour to hour changes that differ from what might have been predicted a day-ahead as long as a load on the other side of the schedule can accommodate the change. However, OATTs often do address over-generation conditions in the tariff. Normally a balancing authority (BA) will maintain a schedule even if there are imbalances (the generator will pay the costs of imbalance energy and potentially punitive fees if it deviates from its schedule). However, if over-generation conditions prevent the BA from maintaining a schedule within reliability constraints, generators are likely to be required to reduce their scheduled level of output until the over-generation condition is ameliorated.

In regions with organized wholesale markets, open access is enforced through market designs that provide a transparent forum for generators and loads to trade electricity. In organized wholesale markets, market operators (i.e., ISO or RTO) settle trades between generators and loads in the energy market, and charge imbalance fees to generators that do not follow dispatch instructions. Additional services ancillary to the energy market, such as regulation reserves and operating reserves are paid for by loads. The FERC approves the market structure and rules used in these organized wholesale markets. In most organized wholesale markets in the U.S., the prices for ancillary services are based on a co-optimization of wholesale energy and ancillary service requirements (e.g., ISO-NE, NYISO, PJM, MISO, ERCOT, and CAISO). Co-optimization of energy and ancillary services explicitly recognizes the tradeoffs between using the available generation capacity to provide either energy or reserves in determining schedules and market prices.

In contrast to the OATTs, day-ahead forecast errors can result in lost revenues to generators in organized markets. A generator that is awarded a particular day-ahead schedule based on the day-ahead forecast will be responsible for purchasing energy from the real-time market for generation deficiencies or will be paid the real-time price for any excess generation relative to the day-ahead schedule. If an under-forecast in the day-ahead exacerbates excess generation in the real-time energy market, the excess generation from the generator will earn less in the real-time market than it could have earned in the day-ahead market had the forecast been more accurate. Organized markets also do not explicitly have charges related to over-generation. However, situations with excess generation and insufficient load will generally be preceded by very low or even negative prices, which can appear both in the real-time and day-ahead energy market. If low or negative prices in energy markets are insufficient to back down generators (including price-sensitive wind generators) or produce an increase in demand, then market operators will rely on out-of-market dispatch instructions to curtail generation.

2.6 Intersection of Variable Generation Characteristics and the Bulk Power System

The approximate mapping of the operational characteristics of variable generation resources to the bulk power system operations is illustrated in Table 4 with a black dot. The presence of a black dot or the lack thereof is based on the timing of the procurement of the bulk power system service to manage the identified operational characteristic in an attempt to minimize cost. For example, a dot is placed at the intersection of the <2 hour forecast error and the Load Following/Imbalance energy because short-term forecast errors in wind (<2 hour forecasts) lead to higher or lower wind generation than scheduled. To manage these short-term forecast errors, the power system operator either procures additional imbalance energy from existing thermal generators or absorbs the additional imbalance energy. Short-term forecast errors can also impact the deployment of reserves if conventional generators are set to the wrong set-point and the units that are providing reserves are the only units available to absorb this imbalance. Depending on operational practices used in different regions, additional units standing by as supplemental reserves may be deployed to manage infrequent, very large forecast errors. In contrast, several of the bulk-power system operations are not available to manage forecast errors of variable generation that occur less than two hours ahead. A black dot is *not* shown at the intersection of the <2 hour forecast error and hour-ahead energy in Table 4 because hour-ahead energy markets would be closed by the time that it is realized that the short-term wind forecast was incorrect. In terms of trying to account for costs, it would be possible to manage large multi-hour ramps by procuring significantly greater amounts of regulation reserves from existing thermal generators. However, to do so would be substantially more expensive than relying on thermal generators that offer imbalance energy or hour-ahead energy services. Hence, though it would be possible to include a dot at the intersection of regulation reserves and large multi-hour ramps, we did not choose to do so because that operational characteristic is generally more cost effectively dealt with through the other bulk power system services that are indicated by a dot.

	Operational Characteristics of Variable Generation Resources					
Bulk Power System Operations	**1 min to 5-10 min variability**	**<2 hour forecast error**	**Large multi-hour ramps**	**>24 hour forecast error**	**Variation from avg. daily energy profile**	**Avg. daily energy profile by season**
Spinning Reserves	●	●				
Supplemental Reserves		●	●	●		
Regulation Reserves	●					
Load Following / Imbalance Energy	●	●	●			
Hour-ahead Energy			●	●	●	
Multi-hour Ramping Capability			●	●	●	
Day-ahead Energy			●		●	●
Over-generation				●	●	●
Resource Adequacy					●	●

Table 4. Intersection of variable generation production characteristics and bulk power system operations

3. Demand Response Opportunities

In this section, we identify and describe the current designs of demand response opportunities sponsored by a load-serving entity (LSE) and/or offered by aggregators of retail customers (ARC), including the time scales over which these time-based retail rates or incentive-based programs are expected to produce changes in the electricity consumption of end-use customers. Our discussion of these opportunities focus mainly on smaller (i.e., mass market) retail customers who are enabled to participate in such opportunities through a utility's investment in AMI or other DR-enabling technology. We also identify the bulk power system services that can be provided by the current generation of LSE-sponsored and ARC-offered demand response opportunities as well as those that could be supplied in the future if these opportunities are expanded.

3.1 Current Designs

Table 5 contains a list of the current demand response opportunities organized by the type of DR signal (i.e., price level charged to retail customers for electric commodity purchases vs. system state indicator) used to elicit a change in a customer's consumption of electricity.[15]

The different time-based retail rates all assume that customers will alter their consumption of electricity in response to changes in its pricing or their resultant costs. *Time of use pricing* (TOU) rates provide different but pre-determined prices over broadly defined pre-specified periods (e.g., summer weekdays between 12 noon and 6 PM, summer nights and weekend). *Critical peak pricing* (CPP) rates generally institute a single pre-determined price or sometimes variable price schedules during a narrowly defined period (e.g., summer weekday between 12 noon and 6 PM) that is only applied during specific system operating or market conditions (e.g., 30-minute operating reserve shortages, wholesale prices exceed $250/MWh). *Critical peak rebate* (CPR, also called Peak-Time Rebate) is similar to CPP, except that customers receive billing credits at the indicated pre-determined rebate price only for consumption below some deemed level of electricity consumption (i.e., a customer specific baseline); all other consumption is priced at the otherwise applicable tariff rate.[16] *Real time pricing* (RTP) represents a rate schedule where the price can differ by hour of the day. There are two common forms of RTP: one that provides the twenty-four hour price schedule a day in advance (DA-RTP)

[15] Table 5 portrays the different demand response opportunities as independent. However, in theory and practice, LSE (and ARC) may combine different DR opportunities (e.g., day-ahead RTP with a CPP price overlay). For ease of exposition, we will retain the singular nature of each time-based rate and DR program when discussing the various DR opportunities. It should also be noted that the definitions provided correspond with those most frequently observed in the industry at present. More dynamic rate designs than those cited are certainly possible (e.g., price changes every 15 minutes) and may be offered by LSE in the future.

[16] There is debate as to the accuracy of portraying Critical Peak Rebate as a retail electricity rate offering. CPR stipulates a payment rate to be provided to customers for energy reductions relative to a baseline level of consumption during specific periods. In contrast, all other dynamic pricing retail rates stipulate the price of electricity during specific periods. As such CPR could also be characterized as an incentive-based DR Program. However, given the common typology that has developed in the electric utility industry in describing this DR opportunity, we have opted to classify CPR as a retail rate for consistency purposes.

and another that provides the hourly price within 60 minutes after consumption has already occurred (RT-RTP).[17]

Incentive-based DR programs are much different from retail rates in that they provide an explicit payment or billing credit if the customer has the potential and is willing to alter their electricity consumption in response to a system event. *Direct load control* (DLC) programs provide a utility with the opportunity to directly control via radio or other remote means the customer's various electricity consuming devices (e.g., air conditioning equipment or thermostats, electric water heaters, pool pumps, and electric heating equipment). In some cases, customers have the ability to override these controls. *Interruptible/Curtailable* (I/C) programs have historically been targeted at large commercial and industrial customers where some portions of their load deemed by the customer to be "non-firm" could be physically disconnected from the grid with little to no notice, either automatically or manually. For example, large industrial customers in Texas have under-frequency relays that can be tripped by the utility if bulk power system conditions warrant a rapid reduction in electricity demand. *Emergency DR resource* programs usually provide load reductions to the bulk power system when grid conditions are expected to deteriorate beyond acceptable reserve margins. Such programs are usually voluntary and provide a performance payment to customers for verified load reductions relative to some deemed baseline level of consumption. *Capacity resource* programs are dispatched under similar circumstances to Emergency DR Resource programs but provide an up-front payment in exchange for a requirement to reduce the agreed-upon amount of electricity when an event is called (and typically include financial penalties if customers or aggregators do not meet their subscribed load curtailment commitment). *Energy resource* programs provide end-use customers the opportunity to participate directly or indirectly in wholesale electricity markets by being paid for altering their consumption of electricity relative to some determination of what they would have consumed absent the DR event signal (i.e., baseline). *Ancillary service* programs also provide end-use customers access to wholesale markets, but in this case to provide operating reserves (and regulation services in a limited number of cases) in exchange for a payment at the wholesale market price for that service.

[17] Although there are additional variants to RTP rate designs, we focus on these two because they have the most impact on customer consumption decisions. Other RTP designs provide the appropriate marginal price of electricity, but may do so within a hedged instrument (two-part RTP) or with a price adder to represent scarcity pricing. In the future, the design of DA-RTP or RT-RTP tariffs may change if the hourly granularity of pricing is altered (e.g., 5 to 15 minutes).

Time-Based Retail Rates *DR Signal: Price Level*	Incentive-Based Programs *DR Signal: System State*
Time-of-Use (TOU)	Direct Load Control (DLC)
Critical Peak Rebate (CPR)	Interruptible/Curtailable (I/C)
Critical Peak Pricing (CPP)	Emergency DR Resource
Day-Ahead Real-Time Pricing (DA-RTP)	Capacity Resource
Real-Time Real-Time Pricing (RT-RTP)	Energy Resource
	Ancillary Services Resource

Table 5. Current demand response opportunities

All forms of demand response anticipate that either the utility will directly control end uses (DLC or I/C) or the customer will manually or automatically alter their consumption of electricity over some time period based on a DR signal (i.e., pricing or system state) provided by the LSE or ARC. The maximum number of events (e.g., ten times per year) that can be called during a year, the time interval between events (e.g., daily, multiple times within a day, no more than 3 days in a row), the advance notification period (e.g., <1 minute, 10-30 minutes, 2 hours) of an event signal change, and the maximum duration of system events will dictate the ability of the LSE or ARC to direct the commencement and duration of changes in end-use customer consumption. Table 6 summarizes the time scale of advance notice, duration and frequency of signal changes for each type of DR opportunity, which are discussed in more detail below.

The advance notice of a DR signal change provides customers with an opportunity to prepare for and execute strategies which affects the ability of a LSE or ARC to direct the timing of changes in consumption. For incentive-based DR programs that target ancillary services where pool pumps, water heaters and residential HVAC systems are controlled by the utility for very short time periods (i.e., minutes not hours), the level of advanced notice likely has little to no effect on the level of response. However, for other types of DR opportunities, mass market customers need to process the advance notification and act on it either manually or through automation and control technology, which is likely to have implications for customers' ability to alter consumption patterns and their willingness to participate in the rate or program. Unfortunately, there has been very little research in this area with respect to mass market customers, so little is known about how the level of advanced notice will affect either their participation decision or response capabilities.

The full range of demand response opportunities offered today assumes various customers are able to alter their consumption for varying time periods (e.g., from minutes to several hours) depending on their individual ability. The "duration of response" is a function of, at a minimum, how granular the DR signaling periods are for each type of demand response opportunity (e.g., hourly for RTP) and, at a maximum, the length of time the signal remains the same (e.g., multiple hours of high prices under RTP).[18] There may be some concerns that many mass

[18] For example, under current designs for real-time pricing, the duration of response cannot be less than one hour because prices are provided on an hourly basis by utilities. Likewise, the duration of response for CPP/CPR tariffs typically involves a pre-defined event period of several consecutive hours.

market customers will be unwilling, if not unable, to curtail loads over long time periods (> 6 hours). Several evaluations of Independent System Operators or Regional Transmission Operators (ISO/RTO) DR programs have attempted to empirically examine customer preferences for load reductions over event periods of different lengths to determine whether subscription (and therefore total performance) erodes over time.[19] Large commercial and industrial customers have the ability to implement strategies to extend the duration of response if they have sufficient advance notice to execute these strategies (e.g., paper products manufacturers can rely on large pulp storage facilities), but it is unclear if mass market customers have the same capabilities given the types of load curtailment strategies that can be utilized for their end uses. For example, in commercial office buildings, a popular DR strategy is to allow the temperature in the office space to increase by several degrees. However, once a critical temperature threshold is hit, occupant comfort becomes a concern and thus, building operators are only willing to increase temperature set points by several degrees. Signaling periods that extend for only a very short period of time (i.e., seconds to minutes) may also be challenging for mass market customers if they must change consumption quickly from one level to another (e.g., manually changing set points on a thermostat to control air conditioning load) but can be accommodated by using automation control technology (e.g., programmable communicating thermostat that directly controls air conditioning load).

Demand response impacts can also vary in terms of how frequently customer consumption is expected to vary. This "frequency of response" is a function of both how granular the signaling periods are but also how frequently those signals change across periods. For example, time-based retail rates (e.g., real-time pricing) provide the opportunity for mass market customers to both reduce consumption when the price is high but also to expand usage when prices are low; the frequency of which depends importantly on the incidence of both high and low prices, which may vary substantially from month-to-month and year-to-year. Such variability is observed in other DR opportunities, especially ancillary services resource programs, and generates concerns about fatigue in customer performance if the LSE/ARC provides signals to alter consumption on a concentrated and frequent basis. Such a lack of persistence would be problematic for system operators and system planners, who need to know what to expect from demand response resources during times when a DR signal indicates a reduction in consumption is warranted as well as when an increase in consumption may be desirable. Eto et al. (2007) illustrates that customers with simple direct load control devices on HVAC systems are willing and able to respond to frequent DR signal changes without serious customer complaints. In contrast, in evaluating the ISO-NE Demand Response Reserves Pilot, KEMA (2010) concluded that performance for even direct load control was highly variable (providing between 0% and 400% of contracted amounts during different events) and decreased over the duration of the four year pilot.

[19] The 2001 and 2002 evaluations of the NYISO's demand response programs (Neenan et al., 2002; Neenan et al., 2003) included an assessment of customer's stated preferences for demand response programs with various and different design elements. Specifically, one design element was the duration of events (e.g., 1, 2 or 4 hours). Customers were given a series of different programs and asked to choose which one they preferred. The results clearly illustrated a preference for events of longer duration. Unfortunately, there has been no formal analysis looking at actual event performance to see if a statistical difference exists for curtailment events of differing duration.

Demand Response Opportunity	Time Scale		
	Advance Notice of Response	Duration of Response	Frequency of Response
Time-Based Retail Rates			
TOU	> 6 months	Length of peak period (e.g., ~4-15 hrs.)	Daily, seasonal, etc.
CPP/CPR	2 – 24 hrs.	Length of critical peak period (e.g., ~2-8 hrs.)	Typically <100 hrs/year
DA-RTP	~24 hrs.	Depends on price level (e.g., ~2-8 hrs.)	Depends on price level
RT-RTP	5 min. – 1 hr. after	Depends on price level (e.g., ~2-8 hrs.)	Depends on price level
Incentive-Based Programs			
Direct Load Control	None	5 – 60 min.	Sometimes limited in tariff
Interruptible/Curtailable	30 – 60 min.	Depends on contract	Sometimes limited in tariff
Emergency DR Resource	2 – 24 hrs.	2 – 4 hrs. minimum	Typically <100 hrs/year
Capacity Resource	2 – 24 hrs.	2 – 4 hrs. minimum	Typically <100 hrs/year
Energy Resource	~5 min.– 24 hrs	Depends on price level	Depends on price level
Ancillary Services Resource	~5 sec. – 30 min.	10 min. – 2 hrs.	Depends on reliability level

Table 6. Typology of demand response opportunities

3.2 DR Opportunities for Mass Market Customers and the Bulk Power System

Targeted changes in the consumption of electricity can have profound effects on the operating characteristics of the bulk power system. If the changes are dependable and predictable, such actions can transform demand response into a resource capable of providing bulk power system services, similar to supply-side generation assets. In this section, we provide a brief overview and assessment of the services that demand response at the mass market level can provide to the bulk power system.[20]

Historically, among mass market customers, direct load control programs have been the most popular in terms of number of programs, customer enrollment, and load response. There has been more limited participation by residential and small commercial customers on time-based retail rates.[21] With the roll-out of advanced metering infrastructure, customers and demand

[20] The following assessment of the bulk power system services that demand response is capable of providing abstracts somewhat from reality in that reliability and/or wholesale market rules in some jurisdictions may preclude the participation of loads to provide these services. Instead, our assessment simply identifies the need met by the bulk power system service and the degree to which demand response could provide that service now as well as in the future. Note that interruptible/curtailable programs are almost exclusively offered to large commercial and industrial customers. As such, they will be excluded from this point forward in the discussion of DR opportunities that relate to mass market customers.

[21] According to FERC (2011), about ~5.6 million residential, commercial and industrial customers are enrolled in a DLC program and ~1.1 million residential, commercial and industrial customers take service under TOU rates. To put these enrollment figures into some perspective, Arizona Public Service has one of the most successful residential

response service providers now have the opportunity to provide a much broader range of bulk power system services. First, all mass market customers will have the requisite metering capabilities to capture and price consumption at a highly granular level. Second, technology that is enabled by AMI and smart grid is significantly expanding the ability for all kinds of end-use customers to rapidly change electricity consumption.

Incentive-based programs have the greatest potential to provide a broad array of bulk power services, based on their relatively short advance notification and duration of response requirements (see Table 7). Recent surveys of utility incentive-based DR programs suggests that many utilities have modified direct load control and interruptible/curtailable programs that historically were designed to be called during system emergencies so that these DR programs can now be called when the utility is facing high prices in wholesale energy markets (Bharvirkar et al., 2008; Heffner et al., 2009). Several pilot programs and test-bed studies have illustrated how utility direct load control programs can provide a variety of different types of reserves products (e.g., Eto et al., 2007; Hammerstrom et al., 2007; Eto et al., 2009). For example, PacifiCorp has been using its CoolKeeper program to satisfy Western Electric Coordinating Council (WECC) requirements for non-spinning reserves for over two years (Woychik, 2008). In jurisdictions with organized wholesale markets, several ISO/RTOs have allowed mass market customers to participate in wholesale emergency, capacity and energy market programs through load aggregators (utilities or ARCs) for up to a decade.

Bulk Power System Service	**DLC**	**Emergency DR**	**Capacity**	**Energy**	**Ancillary Services**
Spinning Reserves	○				○
Supplemental Reserves	○	○			○
Regulation Reserves					○
Imbalance Energy	◉			○	
Hour-ahead Energy	◉			○	
Multi-hour Ramping	○				
Day-ahead Energy	◉			○	
Over-generation	○				
Resource Adequacy	●		○		

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◉	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table 7. Ability of mass market customers in incentive-based DR programs to provide various bulk power system services

TOU programs in the U.S. and has over 500,000 customers enrolled in 2010 which represented just over 50% of their residential population.

Because of their lengthy advance notification periods and duration of response attributes, the current generation of time-based retail rates, are incapable of inducing residential customers to alter consumption in the time scales required (i.e., minutes) to provide ancillary services (see Table 8). For example, time of use (TOU) pricing sends a DR signal that is known months in advance and only changes over broad blocks of hours. This type of time-based retail rate can help reduce demand during the on-peak TOU period (which could potentially contribute toward long-term resource adequacy) but is incapable of providing other bulk power system services. As currently designed, other time-based rates (e.g., RTP) could potentially provide a limited degree of energy and ramping services as well as resource adequacy, but only if reliability and/or market rules allow it.[22] Commonwealth Edison and Ameren Illinois are the only two utilities that currently offer real-time pricing to residential customers that are not small pilots. Customers of these two utilities that elect to take service under this RTP tariff are provided with commodity prices on a day-ahead basis and may also elect to participate in PJM's day-ahead and/or real-time economic load response programs. In the U.S., ~70 utilities have offered real time pricing to large commercial and industrial customers (Barbose et al., 2005) over the last 20 years, although relative few utilities have succeeded in attracting significant numbers of customers and/or loads (e.g., Georgia Power, National Grid New York, Duke Energy Carolina). Research indicates that participation rates are higher and switching rates are lower for the day-ahead variety of RTP (i.e., DA-RTP) relative to a design that provides prices to customers on an *ex post* basis (i.e., RT-RTP) (Barbose et al., 2005). The key difference for bulk power system services between these two different rate designs is the ability to influence the grid on a day-ahead basis or on an in-day basis, the latter being more valuable in managing unforeseen grid conditions. However, in order to enable RT-RTP to contribute in the management of sub-hourly energy services at the bulk power system level, the current practice of providing hourly prices after consumption has already occurred will need to change such that the price signal is provided on an *ex ante*, more frequent basis (e.g., every 5-15 minutes).

[22] There have been a few recent demonstration projects and simulation studies that have illustrated how pricing at a highly granular level (e.g., five to 15 minute intervals) could be used to potentially provide imbalance energy and certain kinds of reserves (e.g., Hammerstrom et al., 2007; Sioshansi and Short, 2009). However, these results are not shown in Table 8 because they do not represent pricing designs envisioned to be implemented in the near future for residential customers as there is little to no regulatory or political will to offer such rates.

Bulk Power System Service	TOU	CPR	CPP	DA-RTP	RT-RTP
Spinning Reserves					
Supplemental Reserves					
Regulation Reserves					
Imbalance Energy					○
Hour-ahead Energy					○
Multi-hour Ramping				○	○
Day-ahead Energy				○	○
Over-generation				○	○
Resource Adequacy	○	◉	◉	○	○

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◉	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table 8. Ability of mass market customers on time-based retail rates to provide bulk power system services

3.3 Current DR Providers

The entities that may offer these demand response opportunities to end-use customers vary considerably by the retail and wholesale market environment in which they reside. To wit:

1. **Vertically integrated utilities outside of an ISO/RTO footprint** are the only entities providing both time-based retail rates and incentive-based DR programs, but they may outsource their incentive-based programs to a third party provider through contracts;
2. **Vertically integrated utilities within an ISO/RTO footprint** are the only entities providing time-based retail rates but may or may not be the only entities providing incentive-based DR programs, depending upon state legislation and regulation; and
3. **Utilities within an ISO/RTO footprint in states with retail competition** are likely not the only entities providing time-based retail rates and incentive-based programs.

Over the last 10 years, ISO/RTOs have established organized wholesale energy, capacity and reliability markets in many regions of the U.S. With strong policy support from FERC, ISOs/RTOs have steadily increased the opportunities for utility and non-utility entities to aggregate customer loads and provide demand response resources that participate in these wholesale markets. ISO/RTO markets provided the first significant opportunity for non-utility entities (ARCs) to engage customers and facilitate load participation in wholesale energy markets. Initially, the business models of most ARCs focused on subscribing commercial and industrial customers for ISO/RTO DR programs, although a few ARCs targeted mass market customers. ARCs typically shared the up-front and/or performance payments with the subscribing customer while insulating them somewhat from non-performance penalties through various strategies.[23] Over time, the ARCs realized that they could also serve as third-party implementers of utility retail demand response programs if utilities were interested in and willing to "outsource" program delivery and management. This provided ARC with an opportunity to expand outside of the organized markets in the U.S. Experience to date suggests that ARCs have been reasonably successful at providing such program management and implementation functions in utility DR programs (Davids and Brief, 2010). ARCs and some LSEs with very large direct load control programs have been especially adept at aggregating smaller customers together through the use of complex back-office computing systems and network operations centers that allow them to more selectively dispatch resources to ensure the portfolio provides the contracted for demand response.[24] However, many LSEs are not able to selectively dispatch customers due to a lack of investment in this technology coupled with retail tariff restrictions; this means that they have less flexibility in offering customers tailored solutions that create demand response opportunities.

3.4 Assessing the Potential for Future DR Opportunities

As described in previous sections, the potential for mass market demand response opportunities have grown substantially over the past decade as interval metering costs have come down and the industry has increasingly realized the energy market and societal benefits that can be achieved by inducing customers to alter their consumption on a targeted and timely basis. The future penetration of demand response opportunities will primarily be influenced by three factors:

1. **AMI deployment**: Without advanced meters and the associated communications infrastructure, changes in customer consumption patterns due to time-differentiated changes in the DR signal cannot be captured and used to create a viable customer value proposition for the pursuit of demand response opportunities. Over the past decade, several states selectively expanded deployment of hourly interval meters to smaller commercial and industrial customers on a voluntary basis or in conjunction with retail competition (e.g., CA, NY, NJ, MD, PA). However, system-wide installations of AMI provide mass market customers with advanced meters with two-way communication capabilities, opening up a huge market for demand response opportunities.
2. **Stakeholder acceptance of time-based retail rates**: The installation of advanced metering through AMI provides electric utilities with the technical basis to price electricity on a time-differentiated basis. The degree to which state regulators and stakeholders are willing to allow utilities to actually offer time-based retail rates, either as default or a well-marketed optional service, is a first-order question. Ultimately, customer acceptance of time-based retail rates will significantly influence the future demand response potential.
3. **Customer acceptance of automation/control technology**: Results from many DR pilots have suggested that automation/control technology substantially increases customer's

[23] For example, an ARC may enroll more customers and subscribed load reductions than they would actually commit to deliver to an ISO during a system event.
[24] These systems include custom-designed software and hardware that provide notification to participants of an impending event, dispatch instructions for customer energy management systems, and calculate and report baseline and load impacts to justify and/or receive payments from the utility or ISO/RTO program administrator.

ability to alter their consumption of electricity in response to a DR signal (Faruqui and Sergici, 2010). The challenges facing utilities (and policymakers) is to motivate large numbers of customers to accept these technologies into their homes and businesses, given growing concerns being raised about the utility becoming "big brother" for the federal government (e.g., Bosley, 2010; Riddell, 2010) and the need for some sort of value proposition to induce their widespread acceptance.

Current estimates indicate ~65 million advanced meters could be installed in the U.S. over the next decade, if all existing proposals for meter deployment are achieved (IEE, 2010). However, several regulatory commissions have issued recent decisions that either allow customers in a individual utility (e.g., PGE, 2011) or all customers within a state (e.g., MPUC, 2011) to opt-out of advanced meter installation at their homes for various reasons (e.g., health/safety concerns). However, opt-out rates for advanced meters are not known at this time.

State regulatory proceedings that examine the utility's business case for AMI deployment also illustrate some of the challenges of increasing penetration of DR opportunities among residential and small commercial customers through time-based rates. For example, in the Baltimore Gas and Electric (MPSC, 2010) case, state regulators were sensitive to exposing residential customers, especially at-risk groups like the poor and elderly, to time-based retail rates on an opt-out or mandatory basis based in part on concerns raised by several key stakeholders.[25]

It is also unclear the extent to which enabling automation and information technology will be provided as part of a utility's AMI roll-out and whether customers will be willing to pay some or all of the costs of DR enabling technologies. Over the longer term, policymakers and regulators may need to re-think the regulatory and market design context for facilitating demand response opportunities among mass market customers. Figure 3 conceptually identifies two options each with significant rate and technology implications. Historically, most utilities have bundled incentives and automation/control technology in their load management programs (Option 1). Many utilities have had success at using this bundled approach to provide load management services for specific end uses (e.g., air conditioning) although significant issues have arisen with these programs at some utilities (e.g., customer's lack of control, removal of control switches, limited flexibility). Given advances in control, information and communication technology, it is not certain that this bundled program design approach is optimal going forward as it is now much more feasible to target multiple end uses (e.g., appliances, HVAC equipment, plug loads) and thus a more diverse set of mass market customers. Over the long term, this bundled approach may also constrain the development of vibrant markets for smart appliances, innovative automation options, and new energy services that include a large number of service providers. The alternative approach (Option 2) seeks to establish a clear demarcation between the utility and customer, typically defined at the meter. The utility (or LSE) will operate on their side of the meter by providing customers with incentives and price/event signals. It will then be up to the customer and competitive market providers to offer and support automation/control equipment and services. The National Institute of Standards and Technology (NIST)

[25] National Association of State Utility Consumer Advocates (NASUCA) and the American Association of Retired Persons (AARP) have advocated that customers only be exposed to time-based rate programs exclusively on an opt-in basis (AARP et al., 2010).

development efforts to standardize price, signaling, scheduling, and certain communication options (Priority Action Plans 3, 4, 9, 10 and 17) are a step in this direction.

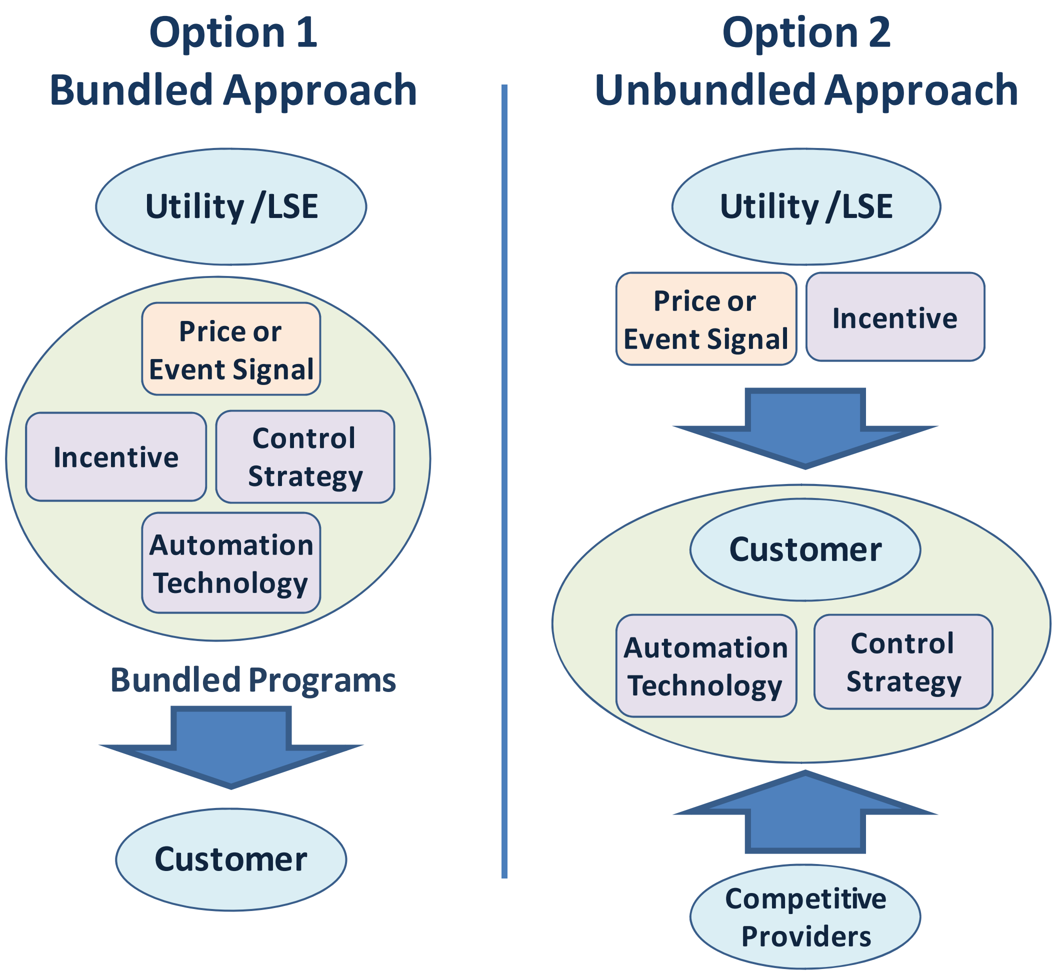
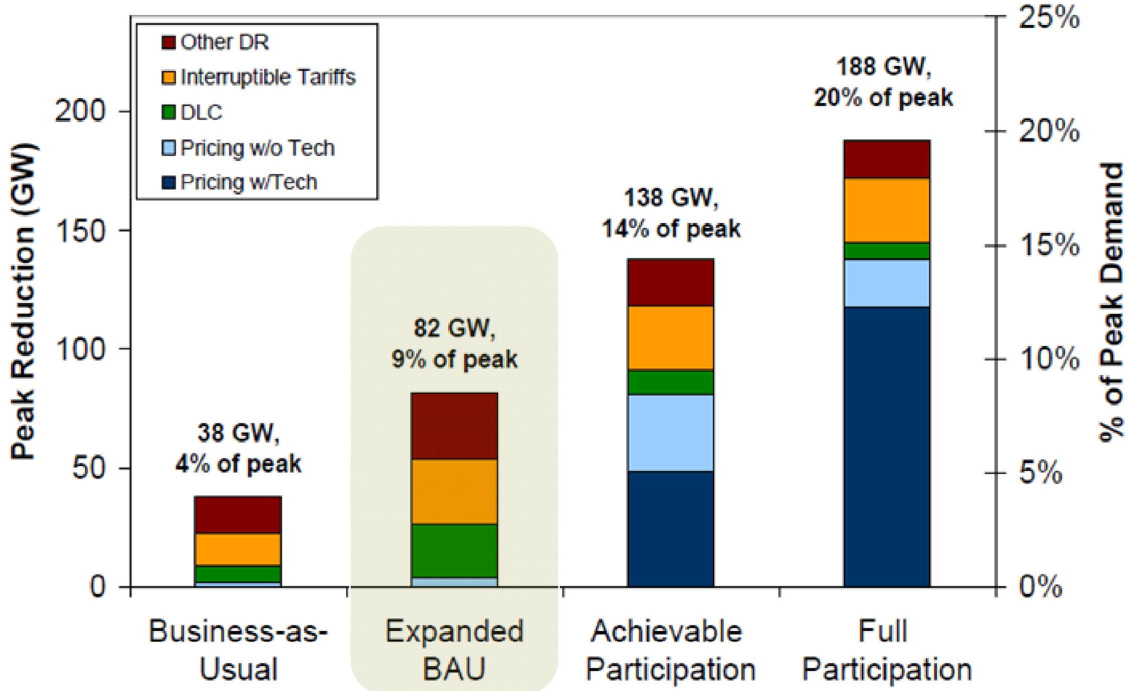


Figure 3. Automation and control technology implementation options

As a practical matter, customer acceptance of time-based retail rates and incentive-based DR programs is intertwined with their acceptance of control and automation technology. The concerns raised by customers and their agents cited above (AARP et al., 2010) can be substantially managed through the use of control and automation technology, which provides customers with the capability to establish price/event response strategies and then "set it and forget it". While the value and economic justification for automation/control is dependent upon the specifics of the DR opportunity, to properly prepare customers with response capability technology implementation will probably have to run in parallel with or actually precede actual rate and program implementation. Extended customer education efforts, creative use of shadow bills, incentives and rebates for enabling technology, and training/information can be used to help address customer acceptance issues. Rigorous evaluations of AMI deployments that test various combinations of time-based pricing options, control technology and customer information/behavior strategies are essential if utilities are to successfully meet this challenge.[26]

For all of these reasons, it seems appropriate to be conservative about the amount of DR potential that is likely to be actually achievable over the next 5-7 years. In 2009, FERC published a national assessment of demand response potential, in which several different participation cases were developed to indicate likely load impacts from demand response by 2019 (FERC, 2009a). The scenarios differed along four key variables: the extent of AMI deployment, the number of eligible customers taking services under time-based retail rates, the number of eligible customers offered automation/control technology, and the basis for incentive-based program participation rates. The Expanded BAU (Business-as-usual) scenario, which assumes partial AMI deployment, modest participation in time-based pricing (~5% on an opt-in basis) and the use of "best practices" to entice customers to participate in incentive-based DR programs, is likely the most realistic scenario over the next five to seven years, given recent regulatory decisions and concerns raised by customer groups (see Figure 4). Under this scenario, by 2019, the bulk of the 82 GW of peak demand reductions from demand response continue to be achieved through direct load control, interruptible/curtailable tariffs, and other incentive-based DR programs, while less than 10% would derive from time-based pricing opportunities. The FERC study also highlights the large potential for time-based rates (see achievable participation scenario) if state regulators put in place a retail rate design policy framework that is linked to the time-based costs of serving customer loads and utilities are successful in educating, informing and motivating customers to enroll on these rates and adjust their usage patterns in response to appropriate signals.

[26] The U.S. Department of Energy is funding just such a series of experiments through its Smart Grid Investment Grant. See www.smartgrid.gov for more information on these consumer behavior studies.



Source: (FERC, 2009a)

Figure 4. Demand response potential by 2019

4. Strategies to manage variable generation resource integration issues

Targeted end-use customer changes in electricity consumption via demand response provide an opportunity to consider DR as a practical tool for managing, to varying degrees, many of the variable generation resource integration issues. This section identifies and analyzes demand response opportunities that are most consistent with each of the previously identified variable generation integration issues, identifies various institutional or market barriers that if changed could expand these DR opportunities, and then discusses existing and proposed approaches to integrate large-scale wind and solar generation in bulk power systems and suggests an analysis framework and factors that should be considered in comparing the relative merits and the mix among the various approaches.

4.1 Demand response strategies to facilitate integration of variable generation

Certain demand response program designs have the potential to alter consumption along time scales amenable to addressing many of the variable generation integration issues, which is why DR has been readily identified in both the popular press and academic literature as a potential solution (e.g., Gul and Stenzel, 2005; NERC, 2009; Taylor, 2009; Milligan and Kirby, 2010).

Several recent studies have investigated the potential for demand response to directly affect net system load (i.e., load – variable generation output) and/or variable generation integration issues.[27] Applications of both pricing and incentive-based demand response opportunities have been widely assessed. Sioshansi and Short (2009) simulated the effects on utilization rates of wind energy when mass market customers responded on a 15-minute basis to DR price signals (i.e., RTP) derived from a wholesale market where high penetration of variable generation resources existed. Klobasa (2010) constructed the potential from shifting consumption in Germany of cooling, washing and drying, dishwashing, and electric heating loads in response to DR price signals that reflect wholesale market prices and quantified how system balancing costs change with high wind energy penetration. Denholm and Margolis (2007) simulated varying levels of load shifting (i.e., 0-10% of daily demand) in response to “real-time” price signals that would indicate availability of low-cost PV generation to consumers.

Based on this literature, the studies tend to assume that demand response programs generally are able to deal with integration problems that have shorter advance notification periods, reasonably lengthy durations and relatively frequent events. However, we are quite skeptical that the DR results suggested in these simulation studies are applicable to the current generation of mass market demand response opportunities in the near term. In our view, these studies typically

[27] Although the focus of this scoping study is to assess the conditions under which mass market customers could help manage the integration of variable generation resources, there is a body of literature that is likewise looking at the capabilities of larger commercial and industrial customers. For example, Kiliccote et al. (2010) evaluate how several specific commercial and industrial end-uses (i.e., ventilation, air conditioning, thermal energy storage and industrial refrigeration) with automated control technology could be used to successfully participate in the integration of high levels of renewable resources in California due to the state’s aggressive RPS requirements. A more exhaustive literature review is outside the scope of this report, but a comprehensive assessment of the role the various customer classes could contribute in the management of VG issues is an area for future research.

assume ambitious mass market customer acceptance of DR opportunities and/or impose customer behavioral response to the DR opportunities that are highly optimistic.[28]

Various field tests are also exploring these DR integration issues in greater depth in real-world applications. GridMobility (2009) has developed a DR product that focuses on the level of renewable content on the bulk power system. This technology is being deployed in Bonneville Power Authority's Mason County People's Utility District #3 on a sample of residential hot water heaters to formally test its effectiveness (MPUD, 2010). Infotility (2009) has likewise developed software that will coordinate and optimize large-scale renewable resources with automated demand response resources. This technology is being deployed in several Marin County, California municipal buildings as part of a on-going pilot program (MEA, 2011).

Between these various field tests and the ongoing academic literature, results illustrating the extent to which DR can manage integration issues associated with high levels of wind and solar generation penetration will be forthcoming over the next several years. Yet many challenges still need to be overcome if the benefits from the DR opportunities deployed in the field tests and simulated in the academic literature are to be fully realized. To better understand how stakeholders could capture these reported benefits from the increased application of demand response as a tool to manage VG integration requires a more thorough assessment of the role existing DR opportunities can play and identify different institutional or market barriers that if changed could expand these DR opportunities.

4.1.1 Role of time-based retail rates

A key challenge with relying on mass market customer response to time-based retail rates as an option for managing variable generation integration issues is that the granularity of DR price signals dictates the degree of efficacy.

For example, nearly all time-based retail rates offered to mass market customers in the U.S. (e.g., TOU, CPP, and CPR) signal system events or high prices for a block of multiple hours. A few utilities offer time-based rates (DA-RTP and RT-RTP) to mass market customers that change no less frequently than every hour. As such, integration issues over short time scales (i.e., sub-hourly) could not be addressed by the current suite of time-based retail rates currently offered to mass market customers.

Moreover, only a subset of time-based retail rates is capable of reflecting exigent system conditions in the DR price signal. For example, a real-time RTP tariff would have some ability to induce customers to change their electricity usage based on in-day system operating and

[28] Sioshansi and Short (2009) appeared to assume that mass market customers are highly capable of responding to price signals provided every 15 minutes, yet no utilities in the U.S. offer real-time DR price signals at such time intervals nor has there been any research that justifies the assumed and ambitious level of customer response. Klobasa (2010) is silent on what would induce customers to alter their usage of washing, cooling and heating loads in the aggressive manner they simulate. Denholm and Margolis (2007) assume a price signal could be constructed which reflects an opportunity to purchase solar electricity during a relatively short and unpredictable window in the mid-day hours, thereby inducing mass market customers to shift consumption away from morning and/or afternoon periods.

market circumstances. Similarly, CPP and CPR tariffs would have some ability only if they are designed to dispatch events in-day, which is not the standard for today's program designs. Other time-based retail rate designs only reflect forecasted conditions on a day-ahead basis (e.g., DA-RTP) or further out in time (e.g., TOU). Only those retail rates capable of reflecting exigent system conditions would have an opportunity to affect the variable generation integration issues which are known less than 24 hours prior to the operating period.

Based on this assessment, time-based retail rates, as currently offered and designed in the United States, would have a very limited opportunity to manage variable generation issues (see Table 9). Even if the granularity in price signals were enhanced to be more reflective of exigent system conditions allowing for greater opportunities to manage variable generation integration issues, mass market customers would also need to accept control technology that would make response at the 60 minute or less time interval possible. Current time-based pricing opportunities, with their relatively long advanced notification periods of a DR signal change, allow customers to curtail or shift loads without necessarily relying on automation or control technology. As the notification delay of the DR signal shortens, mass market customers would need to increasingly rely on technology to respond accordingly to these types of time-based pricing opportunities. Unless the participant value from providing this response and their control of electricity-consuming devices in the home is enough to outweigh the technology costs, customers would likely eschew these types of time-based pricing programs if they are fully responsible for covering the costs or the utility will need to provide some form of cost sharing as a means to induce greater customer acceptance.

A further complicating factor is that those time-based retail rate designs that have the greatest potential to manage variable generation integration issues (i.e., real-time pricing) are exactly those that are the least accepted by regulators, policymakers and stakeholders alike. Only 19 out of 3,454 entities (0.5%) in the United States reported offering real-time pricing rates in 2010 (FERC, 2011) and only a single jurisdiction (Illinois) offers such a rate to its mass market customers. It is not anticipated that this type of retail rate will be highly supported in the near future on a voluntary level, let alone on a mandatory (i.e., default service) basis for residential customers. At present, state regulators and stakeholders are more receptive to introducing CPP or CPR as voluntary (opt-in) time-based rates in conjunction with their AMI deployment. CPP and CPR rate designs do not provide a substantial ability to manage variable generation integration issues. In the future, if such rate designs are made more flexible in terms of event duration, advanced notification, level of the DR signal and are coupled with some form of automation or control technology, they could be significantly more valuable to bulk power systems dealing with high penetrations of variable generation resources.

Variable Generation Integration Issues	**TOU**	**CPR**	**CPP**	**DA-RTP**	**RT-RTP**
1 min. to 5-10 min. variability					
<2 hr. forecast error					○
Large multiple hour ramps					○
>24 hr. forecast error					○
Variation from average daily energy profile		◉	◉	○	○

Average daily energy profile by season	◉			○	○

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◉	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table 9. Assessment of the ability of time-based retail rates to address variable generation integration issues

4.1.2 Role of incentive-based DR programs

Incentive-based DR programs would have significant potential to manage many variable generation integration issues if residential customers are willing to participate in programs whose designs feature short duration and frequent demand response events. Program designs that allow load aggregators to participate effectively and customer acceptance of control and/or automation technology are key factors that will determine the efficacy of these DR programs in managing variable generation integration issues.

There is a rich history of direct load control programs across the U.S. for which customer satisfaction is relatively high. For example, many utilities have implemented successful DLC programs with high market penetration rates for many years.[29] These programs typically rely on controlling air conditioning or hot water system loads or other large electricity consuming devices (e.g., swimming pool pumps, irrigation pumps) that operate coincident with system peak periods, which often occur only a few days in the summer or winter but would be able to address variable generation integration issues over a range of different time scales - from 1 minute to greater than 24 hours (see Table 10).

Capacity programs as well as Emergency DR program are both designed to help the bulk power system avoid potentially catastrophic conditions that could lead to rotating outages. Neither of these programs requires fast response to changes in the DR signal nor are they dispatched frequently (usually less than 5 times a year). Because of these operational characteristics, such programs would not be well suited to address most variable generation integration issues – only those operational characteristics that occur over longer periods of time and occur infrequently (see Table 10).

Variable generation integration issues are more omnipresent and not simply relegated to a few hours each year exclusively during certain seasons, as typically wind and solar resources operate every day of the year. This means that customer load reductions that are only available during certain times of the year (e.g., A/C) would be un able to provide energy and ancillary services year round. Thus, in order to meet energy imbalance or ancillary service market needs associated with increased penetration of variable generation, aggregators would need to supplement these DR resources with others or system operators would need to alter the product definitions or product requirements.

[29] For example, utilities in Florida have enrolled over 1.3 million customers in DLC programs, representing over 10% of the electric customers in the state (FERC, 2011). In 2010, FERC (2011) reported that ~5.6 million customers in the U.S. were enrolled in DLC programs which could provide ~9,000 MW of potential peak load reductions.

In addition, as the notification period of a DR signal change is shortened and the frequency of events increases, complying with such program requirements would ikely be feasible only with substantial reliance on control and/or automation (see Table 10). Mass market customer acceptance of the types of control and/or automation technology required to provide these types of bulk power system services would dictate DR's ability to expand its role in managing variable generation integration issues. If mass market customers continue to be as receptive to such technology as they have been historically with well-marketed utility-administered DLC programs, then DR programs would be able to play an integral part in addressing VG integration issues. At present, though, certain sectors of the population are increasingly expressing concerns about "Big Brother" and outsiders controlling electricity consuming devices with widespread AMI deployment (e.g., Garthwaite, 2009; Vadari, 2009; Hancock, 2010), in spite of the fact that all incentive-based DR programs are offered on an opt-in (i.e., voluntary) basis. In order to reach as broad an audience as possible for these DR opportunities, such barriers to customer acceptance would need to be overcome with thoughtful marketing, education, and privacy controls.

Variable Generation Integration Issues	**DLC**	**Emergency DR**	**Capacity**	**Energy**	**Ancillary Services**
1 min. to 5-10 min. variability	○				○
<2 hr. forecast error	◎	○		○	○
Large multiple hour ramps	◎			○	
>24 hr. forecast error	○			○	
Variation from average daily energy profile		○	○	○	
Average daily energy profile by season					

	Currently not offered and unlikely to be offered in the future
○	Currently not offered or only offered on a limited basis but could be offered more in the future
◎	Currently offered on a limited basis but could be offered more in the future
●	Currently offered on a wide-spread basis and likely to be continued in the future

Table 10. Assessment of the ability of incentive-based DR programs to address variable generation integration issues

4.1.3 Harnessing the diversity and flexibility of mass market customers

Simulation efforts as well as field trials and pilot programs have illustrated how mass market customers can reliably provide bulk power system services as a fleet of distributed resources (e.g., Denholm and Margolis, 2007; Eto et al., 2007; Hammerstrom et al., 2007; Eto et al., 2009; Klobasa, 2010). The two-way communications infrastructure between the utility and customer is an integral part of AMI which provides the opportunity to greatly expand this "fleet" concept to a broad group of mass market customers. If such customers can be coordinated similarly to a portfolio of small and distributed power plants, their combined efforts have the potential to manage a variety of renewable integration issues.

However, time-based tariffs in many states currently impose severe restrictions on the utility's ability to differentially and selectively dispatch customers as a portfolio of resources. The history in the U.S. with utility regulation requires customers to be served on an equal and non-discriminatory basis (Gellhorn and Pierce, 1999). Historically, utilities have typically interpreted this to mean that they have limited ability to tailor and customize tariffed services to individual customers within the same customer class. Historically, utilities have often offered one or more "cycling strategies" in DLC programs that provide customers participation options. However, in order to address integration issues posed by increased penetration of variable generation resources, the next generation of incentive-based DR programs would require "smarter" strategies which take into account both very recent and historical customer usage patterns, "recharge" periods, allow for load curtailments on a targeted geographic basis, and dispatch strategies that may necessitate relying on some customers more heavily than others.[30] Given these changing needs, utilities may not be the entity that is in the best position to harness the diversity and flexibility of selectively dispatching mass market customers, without changes to traditionally tariffed services, if state regulators are not supportive.

As unregulated entities, Aggregators of Retail Customers (ARC) are not currently bound by these same regulatory limitations and as such may be better suited to offer DR opportunities that can treat mass market customers as a customized fleet of distributed resources. ARCs have the ability to aggregate customer response which allows them to insulate their customers from the imposition of non-performance penalties (by using the over-performance from one customer to offset the under-performance of another) and to selectively dispatch program participants to meet a wide array of system needs. In many jurisdictions, ARCs are pushing for expanded opportunities for aggregations of customers to provide ancillary services, balancing energy and other bulk power system services in wholesale market environments (FERC, 2009b). FERC has assisted in this effort by requiring ISO/RTOs to provide greater access to those who wish to enroll in wholesale market DR programs through ARCs (FERC, 2008). In some state and local jurisdictions, utilities are increasingly relying on ARCs as outsourced third-party providers of their DR programs since these private entities have existing technology to readily aggregate and manage customers at a granular level. It is unclear, however, if these third-party providers will be able to take full advantage of these capabilities in their program recruitment and implementation efforts or will instead be bound by the same restrictions on inequitable discrimination and application of penalties for non-performance as the regulated utilities whose incentive-based DR programs they manage.

One way to fully unlock the potential value of diversity and flexibility among mass market customers would be for stakeholders and regulators to develop new tariffs or modify existing tariffs that allow the differential dispatching of DR resources as noted above. Doing so would allow both the utility and any third-party provider greater flexibility in addressing such issues as variable generation integration. It remains to be seen if utilities provided with such tariff changes would take advantage of this opportunity by investing in the necessary infrastructure to

[30] If customers are called upon frequently to provide demand response, program providers may have several temporal concerns to consider. First, historic customer usage patterns may need to be integrated into dispatch algorithms to more accurately determine how much load reduction is likely to be provided by each customer when called upon at a given time. Second, the length of time between DR events (i.e., minutes to hours) must also be considered to produce an accurate prediction of what can be provided, as a customer's curtailment strategy may require a "recharge period" where a DR resource is partially or wholly unavailable. In addition to temporal issues, bulk power system service needs differ based on geographic requirements which may necessitate the inclusion of a spatial quality to a utility's DR dispatch strategy and result in a reliance on some customers more than others.

dispatch their own DR resources as a portfolio or pursuing with increased vigor third-party entities that already have this capability.

Another barrier to maximizing the value of the DR capability of mass market customers is the existing rules for wholesale markets and reliability requirements, which were initially designed and subsequently evolved under a "generator-only" supply-side paradigm. New and future incentive-based DR programs could provide additional bulk power system services but the value they create would not be fully captured without changes to certain wholesale market and reliability rules. Some ISO/RTOs and reliability councils have already begun this process by expanding product definitions to include demand response as a provider of certain types of ancillary services. For example, the Electricity Reliability Council of Texas (ERCOT) allows demand response to participate in its spinning reserve, supplemental reserve and balancing-up energy markets. PJM and MISO both provide opportunities for demand response to provide spinning reserve and regulation services. Outside of ISO/RTO jurisdictions, the Western Electric Coordinating Council specifically allows PacifiCorp's direct load control program to satisfy a portion of the utility's non-spinning reserve requirements. In all cases, technical issues (e.g., communications, measurement and verification) had to be resolved before system operators and reliability planners could be confident that aggregations of customers would behave comparably, both in terms of speed and predictability, to a supply-side resource. For example, definitions of bulk power system services may have to be altered to access balancing services from demand response (along with other new sources like storage or variable generation). In most organized wholesale markets, the balancing service requires providers to provide both balancing up and balancing down energy (i.e., the services are not separately defined). While it is possible for some loads to provide balancing up energy (i.e., curtailment of demand) and balancing down energy (i.e. an increase in demand), requiring all participating loads to provide symmetrical capabilities for balancing up and down inhibits participation and restricts access to those resources. Defining a separate balancing up from a balancing down service enables loads (along with other resources) which are capable of only providing unidirectional balancing service to still participate in such markets.

4.2 Other existing and planned strategies to facilitate integration of variable generation

Historically, fossil-fuel based and large hydroelectric generation resources have provided the majority of the bulk power system's services. However, as variable generation resources have increased in the U.S., system operators and policymakers are considering various strategies, in addition to demand response, to augment existing approaches for managing the integration of large-scale variable generation, including: (1) improved forecasting tools to increase the accuracy of expected output from variable generators, (2) technology improvements in variable generation that enable these resources to provide some bulk power system services, (3) investing to increase the transmission capacity of the bulk power system, (4) implementing changes in the operating structure of the bulk power system (e.g. larger balancing authorities) or (5) instituting changes to existing wholesale power market design (e.g., intra-hour markets in the West).

Over the past 10-15 years, significant progress has been made in the field of forecasting due to increased cost-effective computing power and improvements in analytical methods for modeling both weather and the physical operating characteristics of variable generation technologies. As such, the increased level of precision with which VG electricity production can be forecasted reduces the error that system operators must contend with when determining how to best balance supply and demand (e.g., NYISO, 2008; NERC, 2009).

Recent technological advances also allow newer wind and solar generation facilities to provide a subset of bulk power system services, thereby managing some of the issues this class of supply assets imposes on the grid. For example, advanced wind plant controls can pitch blades to reduce output below the maximum potential in order to curtail power production, provide regulation down services, or limit the rate at which wind plants ramp up (NERC, 2009). Similar to the changes needed to enable demand response to provide balancing services, bulk power system service definitions may need to be altered in order for variable generation to provide regulation down without also having to provide regulation up.

Investing in increased transmission capacity between areas or in transmission to connect regions that were otherwise electrically isolated from each can also help mange variable generation. Increasing transmission capacity reduces bottlenecks that create operational constraints in balancing the system. Additional transmission capacity between different regions allows the aggregation of geographically diverse variable resources and thereby reduces the net variability and uncertainty. Accessing this diversity between regions requires that institutional arrangements between various regions allow sharing of resources and variability (Enernex Corp., 2010; Sims et al., 2011).

An approach related to transmission expansion involves changes in electricity market structure and/or design. For example, a number of studies have proposed expanding the geographic footprint of balancing authorities responsible for maintaining system reliability. By doing so, a system operator increases access to a more geographically diverse set of variable generation resources, thereby reducing the relative magnitude of the integration issues from any single facility (e.g., a major weather event that substantially affects wind plant production) (GE Energy, 2010). In addition, a bigger system footprint provides greater access to a more diverse set of flexible traditional generation resources which should allow system operators to better manage the bulk power system and manage VG integration issues (Kirby and Milligan, 2008). Increasing access to a more diverse set of generation resources can also be addressed in part by increased granularity in scheduling times between balancing areas (e.g., sub-hourly and/or dynamic scheduling) and mechanisms to provide incentives for utilization of the flexibility of existing plants (e.g., sub-hourly energy imbalance markets). The potential development of an energy imbalance market within the WECC structured in a similar manner to the SPP energy imbalance market would increase access to the flexibility of existing plants and reduce balancing costs (WECC, 2010; E-Three, 2011).

4.3 Analysis framework to compare strategies to address variable generation integration issues

Ultimately, the preferred portfolio of strategies for managing variable generation integration issues will be significantly influenced by relative costs, benefits and perceived risks. Determining the attractiveness of demand response to provide particular services requires estimating the cost of providing the service from various resources or strategies that would be used in lieu of demand response. Studies of the integration of variable generation into the power system with conventional generation have highlighted several costs including balancing costs, resource adequacy costs, and ramping costs.

For example, several studies in the U.S. have estimated the cost of providing balancing services from conventional generation resources in high wind scenarios systems (Wiser and Bolinger, 2010).[31] A portion of these costs are due to the cost of keeping thermal generators on-line and spinning in order to provide flexibility and reserves. The benefit of a demand response program that could provide balancing services comparable to the thermal generators would include the reduction in system costs from not requiring thermal generators to provide the additional balancing service. Results from the Western Wind and Solar Integration Study (GE Energy, 2010) estimated that the benefits of using demand response instead of spinning reserves from thermal generators would be on the order of $310-450/kW-yr.[32] Determining if a demand response program is a better alternative requires an estimate of the cost of implementing a demand response program. In this particular case, the demand response resource would need to provide reductions in demand with little or no notice for 10-35 hours per year (on average) and could be called on any time of day or season.

In addition to the system operational costs of wind energy, the low capacity credit of wind in many regions means that other sources of capacity may still be needed for planning purposes to meet future load growth or to replace capacity from conventional generators that retire.[33] The low capacity credit of wind would be relatively less important if alternative sources of capacity become inexpensive.[34] Currently, a gas-fired combustion turbine is a standard proxy for a new source of peaking capacity, with cost estimates generally ranging from $70-$170/kW-year. Demand response resources could be a comparable source of capacity provided power system planners can be confident that over similar time horizons these resources can produce load reductions during peak periods. Thus, if demand response were to become a significantly lower

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[31] The system costs associated with increasing operating reserves to account for the increased short-term and long-term variability in electricity production from variable generation resources is typically reported to be less than $10/MWh with many estimates less than $5/MWh of wind in conventional power systems (Wiser and Bolinger, 2010).

[32] In order to manage extreme events with 30% wind and 5% solar including large ramps and forecast errors, additional spinning reserves would be needed in the Western Wind and Solar Integration Study (GE Energy, 2010). Adding sufficient spinning reserves to be able to manage nearly all events would increase the overall system costs by $590 million/yr. If a demand response program were available to help the system operator manage extreme events in lieu of increasing spinning reserves then these costs could be avoided. The study found that 1,300 MW of demand response (subject to 35 hours of interruptions per year on average) would be required to be able to manage 30% wind and 5% solar. The potential benefits of such a DR program would be roughly $450/kW-yr. A program that only interrupted customers for 10 hours per year on average would require closer to 1,900 MW of demand response and would produce benefits of $310/kW-yr.

[33] Wind resources often do not contribute a significant portion of their nameplate capacity to meeting load during peak periods. Thus, adding wind energy does not significantly offset the need to build peaker plants or deploy demand response resources to meet peak loads. In contrast, a plant that produces the same amount of energy as a wind plant as a flat block of power will potentially offset the need to deploy demand response or build peaker plants to meet peak loads equivalent to the nameplate capacity of this "comparator" plant.

[34] The relative difference in the value of wind energy with a low capacity credit to a comparator plant that produces the same amount of energy but has a higher capacity credit results in a relative "cost" associated with the low capacity credit of wind. Depending on the cost of capacity, the costs associated with the low capacity credit of wind have been estimated to be in the range of $5-10/MWh-wind (Gross et al., 2007). Lower costs of capacity would lower the magnitude of this cost associated with the low capacity credit of wind.

cost source of capacity than peaker plants, then the total change in costs if wind were to have a large or small capacity credit would be relatively minor.

Finally, if the ramping capability of existing dispatchable resources is insufficient to meet the expected ramping need due to increased penetration of variable generation resources, new and highly flexible supply side resources may need to be built. The challenge with these kinds of resources is that they operate very infrequently and must recover enough revenue in the limited periods they do run to cover both their fixed and variable costs (i.e., high marginal cost units). In addition, deploying a high marginal cost but flexible unit to maintain the balance between supply and demand during a severe ramp may displace a lower cost, but less flexible unit. This results in additional operating costs in a system with more frequent severe ramps. Demand response opportunities that lessen the magnitude of ramps can offset these investments and increased operating costs.

Demand response resources deployed throughout the United States have been shown thus far to be competitive, from a cost standpoint, with peaking generation facilities to provide such system services as capacity, non-spinning reserves and imbalance energy as evidenced by the steady increase in wholesale market demand response program participation (FERC, 2011). That said, DR service providers have limited experience assessing the costs to acquire demand response resources over the long term, particularly if DR resources are called more frequently in the future (which may affect customer's willingness to participate).[35] These entities have a good amount of experience with operating and eliciting participation in incentive-based DR programs. However, the next generation of DR programs that works with the smart grid to provide a comprehensive suite of bulk power system services will likely require more automation and control technology. To support integration of large-scale variable generation, the frequency of events is likely to be increased while the duration of such events will be decreased such that customers may be unable to participate in these types of programs (i.e., ancillary services) without such technological assistance. How can the LSE/ARC establish a sufficient value function to create a market for customer automation products and services such as these? How, if at all, will the costs of this technology be allocated between the utility and the program participant? What program costs will utilities be allowed to recover from customers (i.e., participants, non-participants)?

Historically, the high cost of deploying advanced metering has precluded many utilities from widely offering time-varying retail rates to residential customers. Investments in AMI technology make it possible for utilities to begin to heavily market these kinds of DR opportunities. Like incentive-based programs, the major costs of future time-based retail rates will also be primarily driven by LSE/ARC efforts to induce customer participation and response. Initially getting customers interested in time-based rates, especially RTP which has the most potential to manage VG integration issues, will certainly require substantial marketing and education efforts to illustrate how customers can alter consumption patterns and save money. In some cases, customers may require a compelling offer of enabling technology and other benefits

[35] Costs associated with inducing customer participation (e.g. marketing, sales) and response (incentive payments) represent a significant share of the DR program costs incurred by LSEs and ARCs. If customers are expected to curtail load much more frequently in the future (e.g. in ancillary services markets), then ARCs may have to sign up more customers in order to develop an aggregated resource if individual customers' willingness to curtail does not change over time.

to facilitate this response, thereby bringing down the barriers to acceptance. Depending on the technology and how the industry evolves, it is unclear how much it will take to achieve the appropriate or desired levels of customer acceptance to RTP or other time-based rate designs. Once customers are on the rates, wide-spread adoption of control or automation technology coupled with on-going education efforts will hopefully improve performance. How much is it worth relative to the value provided? As in the incentive-based programs, how will the costs be allocated?

AMI deployment and the DR opportunities it provides will likely go forward over the next decade regardless of the penetration of variable generation resources. Opportunities for demand response to help manage variable generation integration issues may, however, provide a financial incentive for utilities, ARCs and customers to strongly consider expanding demand response even further and/or increasing the penetration of technology to facilitate this expansion if it is found to be a cost effective and financially attractive strategy. Many policymakers are attempting to arrive at a better understanding of both the costs and benefits from using DR opportunities to manage VG integration issues through targeted research efforts, pilot programs, and other program evaluation activities. Once completed, these results can be used to help assess the relative competitiveness of DR resources compared to existing and planned non-DR options and if additional financial resources should be targeted for increased deployment of DR opportunities in the future.

5. Conclusion

The penetration of renewable generation resources is expected to increase significantly over the next five to ten years (and beyond) in the United States due to a plethora of state and federal policies, incentives, and regulatory mandates as well as increased cost competitiveness with more traditional sources of energy production. The variable and uncertain nature of wind and solar power production in this class of electricity supply resources results in a range of issues system operators must deal with that vary over time scales from seconds to days. A wide variety of strategies are available for managing these integration issues.

The largest variability and uncertainty in variable generation power production is over time periods of 1-12 hours; time scales that are in synch with the operation of most time-based rates and DR programs. The deployment of advanced meters and two-way communications networks between customers and the utility driven by the rollout of Advanced Metering Infrastructure and smart grid will greatly increase demand response opportunities made available to mass market customers. This group of customers likely represents the most significant untapped potential DR resource in the United States (FERC, 2009a). Although time-based rates and incentive-based DR program offered to mass market customers have the potential to be highly effective tools in managing VG issues, to fully achieve the potential smart grid proponents contend exists would require some fundamental changes in the relationships that govern end use customers, their utility and the bulk power system operator.

Real-time pricing coupled with automation/control technology, have the potential to address several variable generation integration issues. However, there appears to be little regulatory and stakeholder support for transitioning mass market customers onto RTP rates as utilities in only one state (Illinois) currently offer these tariffs to residential customers. At present, state regulators and stakeholders are more receptive to introducing CPP or CPR as voluntary (opt-in) time-based rates in conjunction with their AMI deployment. However, CPP and CPR have limited potential to address variable generation integration issues. In the future if such designs are made more flexible in terms of event duration, advanced notification, level of the DR signal and are coupled with some form of automation/control technology, they could be more valuable to bulk power systems dealing with high penetrations of variable generation resources. Moreover, consumer advocates (AARP et al., 2010) have raised concerns about the impacts of any time-based rate on customer bills from just transitioning to these types of retail rates, due in part to embedded cross-subsidies in the existing flat retail rate designs but also due to the coincidence of higher prices being charged at times when usage is likewise greater. Furthermore, questions have arisen about whether mass market customer response to such time-varying rate designs is likely, given the complexity of RTP and even to CPP or TOU relative to the simplicity of the prevailing flat rate, or even possible by such “at-risk” groups (e.g., customers with medical conditions, the elderly and poor). Several recent studies have looked at the response of different “at-risk” groups to various types of time-based rates (e.g., eMeter Strategic Consulting, 2010; Faruqui and Sergici, 2010), although more definitive and consistent evidence will likely be required from future studies to address concerns raised by these stakeholders.

Incentive-based DR programs have significant potential to manage many variable generation integration issues if residential customers are willing to participate in programs whose designs feature short duration and frequent demand response events. Increasingly, mass market customers that subscribe to these incentive-based DR programs would need to rely on control and automation technology to provide the necessary load curtailments. Customer acceptance of control and/or automation technology through thoughtful marketing and education efforts is thus a key factor that would in part determine the efficacy of these DR programs in managing variable generation integration issues.

In many respects, customer acceptance of many DR opportunities is intertwined with their acceptance of control and automation technology. To properly prepare customers with response capabilities, technology implementation would probably have to run in parallel with or actually precede actual rate and program implementation, such that customers would have already established price/event response strategies and then may use their control/automation technology to "set it and forget it". The provision of this control and automation technology equipment and services could pursue two alternative paths. Historically, most utilities have bundled incentives and automation/control technology in their load management programs. Given advances in technology coupled with concerns that utility involvement on the customer-side of the meter will constrain competitive markets, an alternative approach could be considered whereby the utility or LSE will provide customers with DR opportunities but competitive market providers would offer and support automation/control equipment and services.

Accessing the diversity and flexibility of customer demand to facilitate integration of large-scale variable generation would likely to require additional changes in market rules and regulatory policies. For example, many jurisdictions may need to consider modifying existing retail market tariffs so that utilities or ARCs can treat customers as a portfolio of resources that can be differentially dispatched. Similarly, changes to reliability rules should be considered that allow ARCs (or very large customers) the ability to provide the full range of bulk power system services. Finally, wholesale market product definitions may need to be expanded and/or market operations may need to be restructured to allow DR to offer and be paid for providing these services.

As variable generation resources have increased in the U.S., system operators and policymakers are considering a wide range of strategies to integrate large-scale variable generation in addition to demand response, including: (1) improved forecasting tools to increase accuracy of expected output from variable generators, (2) technology improvements in variable generation that enable these resources to provide some bulk power system services, (3) investing to increase the transmission capacity of the bulk power system, (4) implementing changes in the operating structure of the bulk power system (e.g. larger balancing authorities) or (5) instituting changes to existing wholesale power (e.g., intra-hour markets in the West). Ultimately, the preferred portfolio of strategies for managing variable generation integration issues will be significantly influenced by the relative costs, benefits and perceived risks of these various strategies. In this scoping study, we provide a few examples to illustrate the boundary conditions where DR would be a cost-effective solution compared to traditional thermal generation to manage a particular VG integration issue. However, comprehensive assessments will require more systematic analysis of risks, costs and benefits of various DR and non-DR strategies and should be an area for future research. These kinds of determinations will vary by system operating characteristics, generation mix, load and a host of other dynamics that make generalization difficult.

Should DR be deemed a cost effective solution to manage certain VG integration issues, the value generated from such endeavors will likely be just one of many benefits streams used to justify the investment in AMI and smart grid technology. The greater the number of opportunities for DR to provide value, the more likely it will be that utilities and end-users insist that policymakers adopt the necessary changes to facilitate an expansion in the offering and adoption of demand response opportunities.

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Appendix A. Characteristics of Variable Generation Production

Appendix A provides a more detailed discussion of the characteristics of variable generation production which are described in Section 2.3.

A.1 Less than One Minute Variability

Over very short time scales (less than one minute) the aggregate variability of wind plants has been measured as less than 0.2% of the nameplate capacity of the wind plants (Wan, 2005). Less high time-resolution data is available for aggregated solar plants, but smoothing of 10-sec variability even within a single 13.2 MW PV plant suggests that the aggregate variability of high penetrations of PV will be low (Mills et al., 2009; Mills and Wiser, 2010). Inherent thermal inertia in solar thermal plants will further smooth the very short time scale variability of solar thermal plants (DOE, Forthcoming).

A.2 One Minute to Five-Ten Minute Variability

Over the time scale of about five minutes, the variability of aggregated wind plants is still only a portion of the name plate capacity, but rare events can lead to significant changes in wind plant output. Wan (2005) measured ten minute step changes from 250 turbines and found that the output changed by less 3% of nameplate capacity for 78% of the observation period. During more severe events, however, the ten minute step change was as high as 14% of the nameplate capacity. Rare extreme events in ERCOT were similarly shown to lead to ten minute step changes of 14% of nameplate capacity for wind, although these extreme ramp-rates were not sustained for longer periods (Wan, 2011).

Aggregated solar plants are expected to have similar variability to these over these time scales. Wiemeken et al. (2001) show that five minute step changes in PV output greater than 5% of the nameplate capacity of PV in Germany are virtually non-existent. More analysis of data across multiple regions is required for solar.

A.3 Less than Two Hour Forecast Error

Short-term forecasts of VG over the next ten to 60 minutes are used in integrating VG into the bulk power system. The two hour ahead forecast error (root mean square error or RMSE) for aggregated wind is 2.6% for all of Germany (Holttinen et al., 2009). The hour-ahead forecast error (mean absolute error or MAE) for wind in New York was estimated to be 4.1% (GE Energy, 2005). The worst hour ahead forecast errors, however, were 24% of the installed capacity. BPA (2009) expects the most severe 2-hour ahead forecast errors to be about 34% of the nameplate capacity of the installed wind. Extreme 30 minute changes in output in Texas wind plants that exceeded 20% of the wind nameplate capacity occurred only once every 6-7 days or about 50 times per year (GE Energy, 2008). The changes that are due to thunderstorms were forecast about 20 minutes prior to the event occurring. These events typically occurred in the late winter to summer months and were more likely to occur in the early evening (~5pm).

The short-term hour-ahead forecast error of solar was projected to be less than 5% (root mean square error or RMSE) for an array of PV sites in Germany (Hammer et al., 1999).

A.4 Large Multiple Hour Ramps

Sustained changes over multiple hours in the output of wind are triggered by large weather systems or fronts moving through a region or due to diurnal weather patterns (i.e. cold ocean air moving into hot desert regions during the day and vice versa at night). In the case of weather fronts, the sustained ramps can often be forecast to pass through a wind region days ahead of time, but the exact timing of the frontal passage within the day is difficult to predict until a few hours prior to the event. A few notable sustained wind ramping events in Texas have led to a loss of over 50% of the nameplate capacity of wind in 90 minutes in 2007 (GE Energy, 2008) [2875 MW installed at end of 2006, 1,500 MW event] and a loss of over 30% of the nameplate capacity of wind in three hours in 2008 (Ela and Kirby, 2008) [4785 MW at end of 2007 1,500 MW event]. The latter event was coupled with several confounding factors to trigger the need for calling on demand response resources to shed load for a duration of 80 minutes. Since that event, improved wind forecasting has been implemented in the ERCOT control system.

Table A- 1 illustrates that three hour wind ramps for a 20% RPS in the California ISO (with 6,700 MW of wind) are expected to be larger than 30% of wind nameplate capacity in the summer mornings (CAISO, 2007).

3-hr Wind Ramps	Spring	Summer	Fall	Winter
Morning (MW)	-1,646	-2,111	-1,494	-1,296
Evening (MW)	+1,286	+838	+1,038	+870
Max Wind Ramp (% nameplate)	25%	32%	22%	19%

Table A- 1. Wind ramp rates by season

Using the wind dataset from the Western Wind and Solar Integration Study indicates that extreme three hour ramps for 15 GW of wind in Tehachapi, California or the Columbia Gorge in Washington are 50-60% of name plate capacity. Extreme six hour ramps are 65-85% of the nameplate capacity in the same regions. Ramps of these magnitude or greater would occur less than about 5-10 times per year.[36]

For solar, there will be large multiple hour ramps in daily output due to the rising and setting of the sun. These are deterministic and can always be anticipated in system operations, but they will be large particularly for solar plants with tracking. The three hour ramps for 10 GW of solar are estimated be 90% of the nameplate capacity in the Mohave Desert for single axis tracking PV. Irrespective of clouds, this same sized 3 hour ramp would need to be met due the rising and setting of the sun.[37]

[36] Authors' own analysis of data from Western Wind and Solar Integration Study available at: http://www.nrel.gov/wind/integrationdatasets/western/data.html

[37] Authors' own analysis of solar datasets created in a manner similar to the Western Wind and Solar Integration Study.

A.5 Greater than 24 Hour Forecast Error

Wind and solar forecasts of the expected hourly production for a horizon of multiple hours to multiple days are less accurate than very short-term forecasts. Aggregation of forecasts does significantly reduce forecast errors relative to individual sites for both wind and solar, however. Wind forecasts used in power systems in the U.S. are estimated to have RSME errors of 6-8% of wind nameplate capacity (Porter and Rogers, 2010). A large integration study for SPP estimated day-ahead forecast errors to be 9% of nameplate capacity for a case with 25 GW of wind installed (CRA, 2010). Day-ahead forecasts for solar are estimated to be 15% RMSE (Lorenz et al., 2009).

Predicting the timing of wind ramps using day-ahead forecasts is particularly challenging (Greaves et al., 2009). 40-60% of the time that a ramp was forecast day-ahead, a true ramp did occur within 12 hours, but the standard deviation of the timing of wind power ramps was 4 hours. In other words, even when a ramp that was actually forecast did occur, the actual ramp would usually occur within +/- 4 hours of the predicted time.

A.6 Average Daily Energy Profile by Season[38]

The trends of when variable generation produces power can be important for understanding the potential contribution to resource adequacy, the potential challenges with over-generation, and expectations for how much energy variable generator will produce throughout the day. In California, for instance, the wind resource is characterized by significant generation during summer nights followed by very low generation during the day. The difference between the highest average summer nighttime production and the lowest average daytime production can be as great as 50% of the nameplate capacity of wind. Other wind regions can have very different average daily profiles by season, however. In Wyoming, for instance, the difference between the average summer night and a summer day is less than 10% of the nameplate capacity of wind but the difference between the highest average summer production and the highest average winter production is 40% of the nameplate capacity of wind. It is difficult to generalize average daily wind profiles by season due to the diversity of wind resource patterns. But it does appear to be common that wind generation tends to be greatest in the winter or spring seasons and at night.

On the other hand it is easy to characterize the average daily profile of solar resources over a season: solar will change from zero at night to maximum around noon and back to zero at night. The solar resource is strongest in the summer months, but due to inefficiencies with increasing ambient temperatures for both PV and solar thermal plants the spring and fall seasons can lead to the most net solar production. The difference in the seasonal average production of solar in Arizona is about 10% of the nameplate capacity.

A.7 Variation from Average Daily Energy Profile

On any particular day, the actual wind and solar that is forecast for that day may be very different from the average daily profile for that season. In the case of solar, cloud cover due to passing weather systems may lead to solar output that is different than average. Deviations of the aggregate of all solar plants from the average daily profile are can be as much as 40% of the nameplate capacity of solar. The standard deviation of deviations from the average diurnal

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[38] All of the values presented in this Appendix are based on the authors' own analysis of the wind and solar data from the Western Wind and Solar Integration Study.

profile by season for large aggregations of solar sites from several solar regions was less than 15% of the nameplate capacity of solar.

In many regions the particular weather for that day can lead to dramatic deviations from the average daily profile. In California, for instance, the average wind production during a summer day is very low, but a particular weather system may lead to high winds during the day even in the summer. Across multiple different wind regions the standard deviation of the hourly deviations of aggregated wind plants from the average diurnal profile by season was around 25% of the nameplate capacity of wind. Large deviations on particular days were as high as 60% of the nameplate capacity of wind.

Appendix B. Bulk Power System Operations

Appendix B provides a more detailed discussion of the characteristics of bulk power system operations.

B.1 Power Quality

Power system operators need to ensure that voltage and power factor are maintained within specified operating limits. This requires adequate reactive power throughout the network and control over voltage taps. Power quality is usually addressed through interconnection standards rather than market operations for new generation. Power quality and interconnection standards primarily focus on extremely short time scales – second-to-second or even shorter. Because of the short time scales, this is not generally seen as an aspect controlled by system operators but is instead managed primarily through power system planners.

B.2 Operating Reserves (Contingency)

Because the power system is operated in a way to maintain security, the power system must be able to withstand the nearly instantaneous loss of any individual power plant or major transmission line or any other such plausible contingency. Reliability standards require operators to be able to recover from contingencies within 10-15 minutes, depending on the region. In order to meet these reliability standards, power system operators maintain operating reserves that can be deployed in the event of a contingency. These reserves are continuously held and procurement amounts are known multiple days ahead of time. These reserves are deployed infrequently (~20-200 events per year for ~10-60 min) (Eto et al., 2007).

The operating reserves are often characterized by the time required to be fully deployed and the duration of the response (Heffner et al., 2007). The highest quality reserves are called frequency response or primary response reserves. These resources must be able to respond automatically in less than one second to an observed deviation in system frequency that indicates a contingency. These reserves must be available after a contingency for the duration of around 10 minutes.

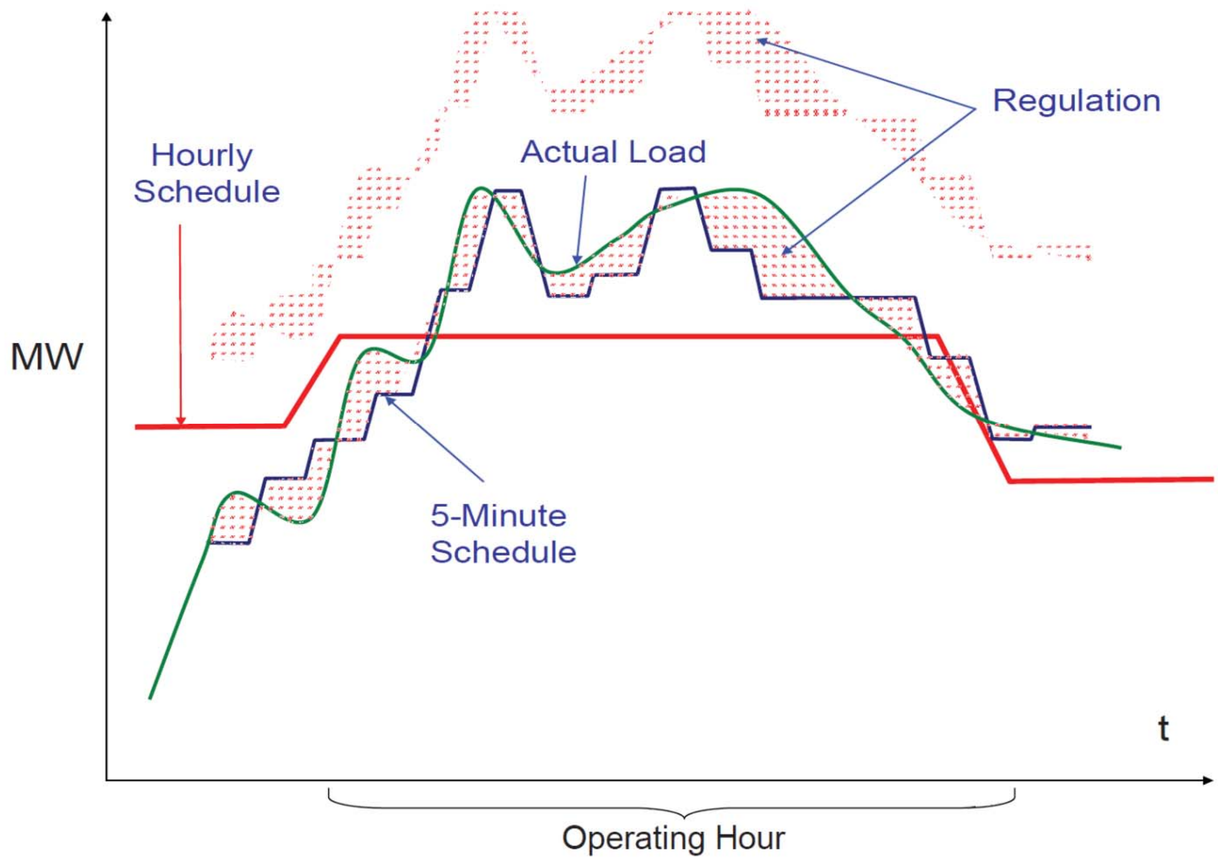
The next tier of reserves is called spinning reserves or secondary response. These resources must able to respond to a control signal sent by the system operator (usually the Automatic Generation Control or AGC) in less than ten seconds and to provide response for roughly 30 minute. In general these resources begin deployment soon after the signal is sent but only need to be fully available within ten minutes. When these reserves are met with generation resources the generator must be online and synchronized with the grid in order to provide spinning reserves.

The last tier of reserves used for contingencies is called supplemental reserves or tertiary response. These resources are able to respond to a short notice from the system operator (dispatch instructions rather than AGC) in ten to 30 minutes. If a generation resource is providing these reserves then the generator can be offline prior to being deployed for a contingency event. The response may need to be provided for multiple hours.

B.3 Regulation Reserves (Normal Operation)

In addition to reserves required to respond to infrequent contingencies, system operators procure regulating reserves to maintain a balance between load and supply during normal operations.

Regulation reserves are required to manage most deviations from dispatched generation and load in between dispatch periods (~five minutes to one hour, depending on the market). Regulation reserves respond to a control signal from system operators that are sent out as frequently as every four seconds (AGC). The full amount of regulation reserve capacity needs to be available within one minute. Some portion of the regulation reserves is continuously deployed, but the full regulation reserve capacity is rarely used. Ideally regulation is a net-zero energy service within the dispatch period. However, if the generation dispatch exceeds the average load during a dispatch period then regulation reserves become a net supplier of energy during the dispatch period. The amount of regulation reserves that will be procured for an operating period is generally determined days ahead of time, depends on the accuracy of forecasting of the actual average net load for the next dispatch schedule and the variability of the net load around the actual average net load within the dispatch period. Increasing the variability and uncertainty leads to an increase in the regulation requirement. Figure B- 1 illustrates the regulation reserve deployment during an operating hour with 5-min dispatch schedules.

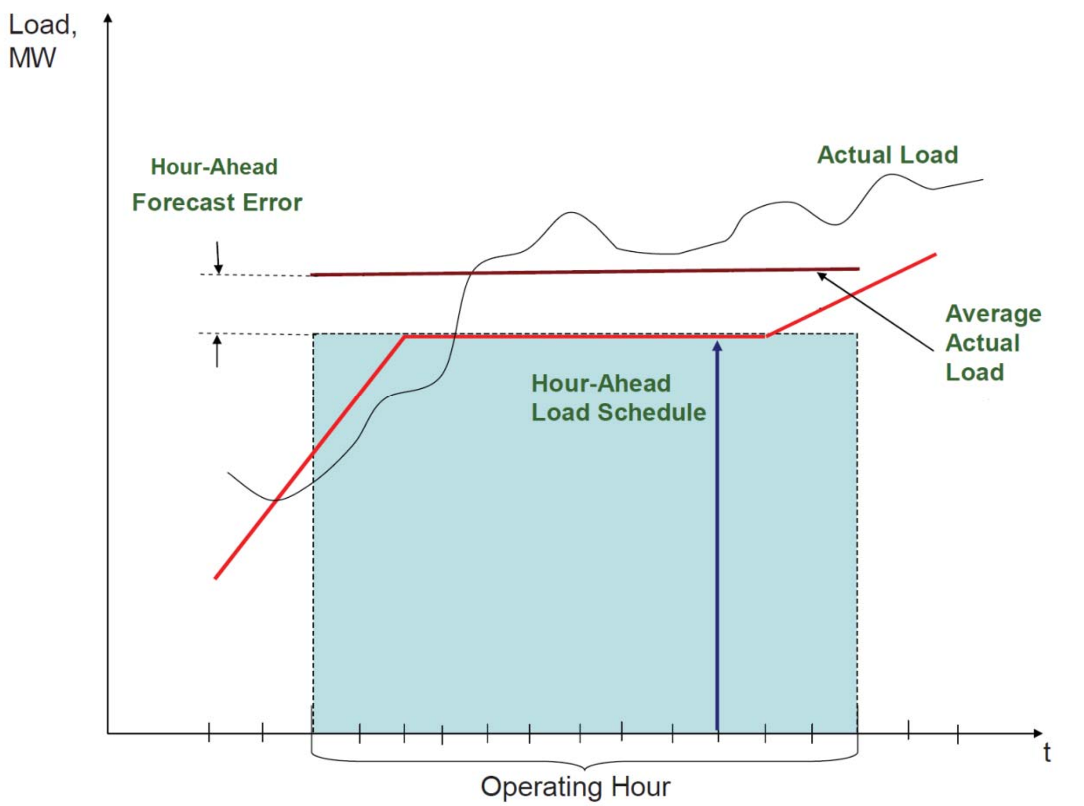


Source: (CAISO, 2007)

Figure B- 1. Example of regulation reserve deployment

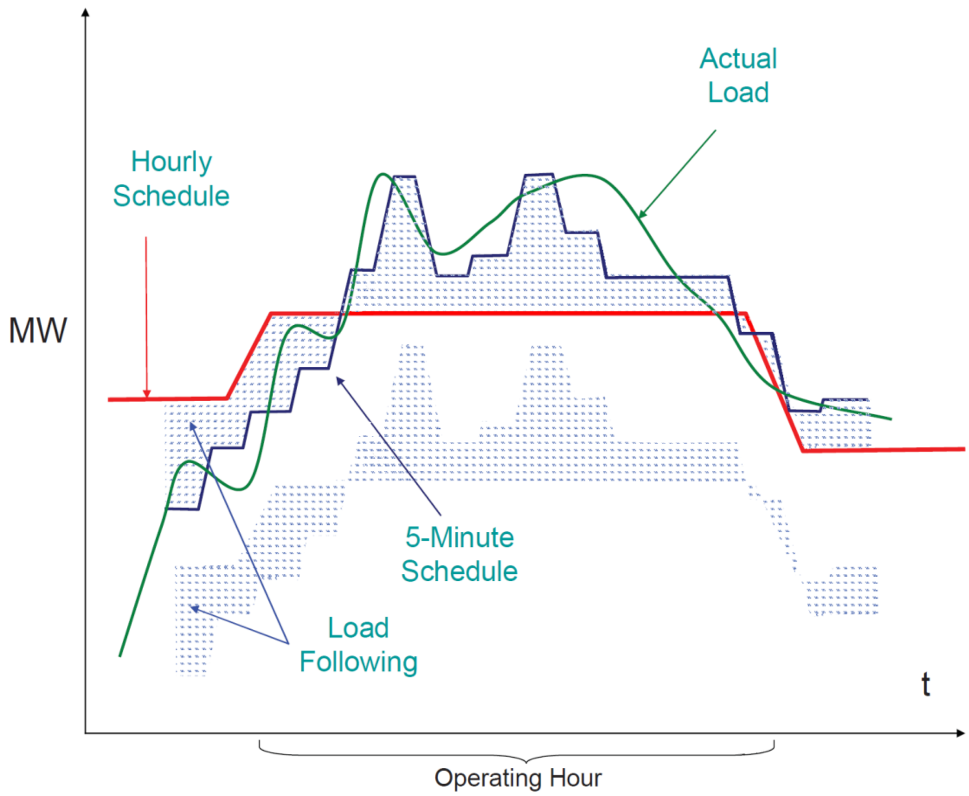
B.4 Load Following/Imbalance/Supplemental Energy

Whereas regulation reserves are controlled using automatic generation control signals, regular dispatch schedules are used to change the output of generation over longer periods. The resources that are dispatched within an operating hour by system operators are called the load following resources. Over an operating hour the imbalance energy is the difference between the hour-ahead schedules and the actual average net load. The magnitude of the imbalance over an hour depends on the accuracy of the hour-ahead forecast. Within the hour the load following resources are dispatched to follow the load on regular dispatch schedules (every five to 15 minutes). If the hour-ahead schedules are very different than the actual hourly average net load, then load following resources will provide a large amount of net energy (or load) over the operating hour (Figure B- 2). In regions with fast energy markets (~5 minute real time markets) load following is provided by dispatching the resources that participate in the real-time market. Some markets call these resources the supplemental energy stack. Typically the lowest cost resource is dispatched first, then as more load following is required, the system operators move "up the stack" to dispatch higher cost resources. Load following resources are continuously deployed, but the frequency by which a particular resource is deployed depends on how far up the stack the resource is. A very expensive resource will be deployed infrequently, but an increase in the hour-ahead forecast uncertainty and the variability of the net load between the actual hourly average net load and the dispatch schedule will lead to an increase in the deployment of load following resources (Figure B- 3).



Source: (CAISO, 2007)

Figure B- 2. Imbalance energy operations



Source: (CAISO, 2007)

Figure B- 3. Real-time bulk power system operations

B.5 Wholesale Energy – Hour-ahead and Day-ahead

The load following and regulation resources are used to maintain a balance around the hourly schedules for generation or load. In a region that uses only bi-lateral markets these schedules are based on balanced bi-lateral transactions between loads and generators (i.e., a generator schedules to provide 100 MW of power and a load schedules to consume 100 MW of power). In regions with organized wholesale markets, un-balanced load from load-serving entities is met by bids from available generation. In either case, schedules for load and generation are usually submitted to system operators or balancing authorities at least an hour-ahead of the operating hour.

In addition to hour-ahead scheduling, most regions with organized wholesale markets provide a day-ahead market that will match day-ahead forecasts of load with day-ahead supply schedules. These day-ahead schedules provide generators with a feasible schedule that allows the generator sufficient time to start-up in order to be ready to supply energy at the scheduled time. This is called the unit-commitment process. If the real time load turns out to be different than what was forecasted day ahead, units that take significant time to start-up may not be available in real time to meet load. Instead more expensive but faster starting units will be scheduled in the hour-ahead time horizon. An increase in the day-ahead forecast error reduces the efficiency of the unit commitment process and can increase operating costs.

B.6 Multiple Hour Ramping Capability

Changes in demand for wholesale energy and imbalance energy in the same direction for long periods (such as the morning pick-up) require adequate ramping capability of the dispatchable generation in the market and the supplemental energy stack. Insufficient ramping capability will lead to deployment of reserves to provide energy or load shedding. Large ramps in load are to some degree forecastable on a day-ahead basis, as they typically follow diurnal patterns that vary with the seasons.

B.7 Over-generation

If markets cannot clear due to insufficient demand to absorb the generation, or system operators cannot dispatch load-following resources to a lower level due to minimum generation constraints then out-of-market actions may be required to maintain balanced operation. This condition is known as over-generation and can be addressed by de-committing units, curtailing generation output, or increasing demand. Over-generation conditions can often be forecasted on a day-ahead basis.

B.8 Resource Adequacy

Reserves, dispatch, and schedules are all used by system operators to maintain a balance between supply and demand using available resources. In addition, planners at load serving entities, generation companies, balancing authorities, and reliability organizations consistently look multiple years into the future to ensure that sufficient flexible demand or generation capacity exists to meet future electricity requirements. This is knows as resource adequacy. In the past, resource adequacy focused almost entirely on ensuring that adequate resources would be available to meet peak loads, but increasingly planners are evaluating flexibility (ramping capability, minimum generation levels, and start-up and shut-down times) in resource adequacy studies.

Depending on the region, resource adequacy is left to: load-serving entities to determine on their own (with the potential for being faced with high energy market prices if they do not procure adequate resources); is mandated by regulators; or is met through a separate capacity market auxiliary to the energy market. For example, ERCOT leaves resource adequacy to load-serving entities while ISO-NE uses a forward capacity market that looks three years into the future to ensure resource adequacy.

Resources that contribute to resource adequacy are expected to be available during times of scarcity in the energy markets. Scarcity can be caused by high loads, but it can also be caused by a shortage of generation if several units are offline due to maintenance needs. The most severe periods of scarcity are generally less than 10% of the hours in a year.