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An Assessment of the Role Mass Market Demand Response Could Play in Contributing to the Management of Variable Generation Integration Issues

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

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Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
ARC	Aggregator of Retail Customers
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
DA-RTP	Day-ahead Real Time Pricing
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas, Inc.
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
Hr.	Hour
HVAC	Heating, Ventilation and Air Conditioning
I/C	Interruptible/Curtailable
IEE	Institution of Electrical Engineers
ISO-NE	Independent System Operator New England, Inc.
ISO/RTO	Independent System Operator / Regional Transmission Operator
LSE	Load Serving Entity
Min.	Minute
MISO	Midwest Independent Transmission System Operator, Inc.
MPSC	Maryland Public Service Commission
MPUC	Maine Public Utilities Commission
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
PGE	Pacific Gas and Electric Company
PJM	Pennsylvania, New Jersey and Maryland Interconnection, LLC
RTP	Real Time Pricing
RT-RTP	Real-time Real Time Pricing
Sec.	Second
TOU	Time of Use Pricing
U.S.	United States
VG	Variable Generation

Abstract

The penetration of wind and solar generating resources is expected to dramatically increase in the United States over the coming years. It is widely understood that large scale deployment of these types of renewable energy sources (e.g., wind, solar) that have variable and less predictable production characteristics than traditional thermal resources poses integration challenges for bulk power system operators. At present, bulk power system operators primarily utilize strategies that rely on existing thermal generation resources and improved wind and solar energy production forecasts to manage this uncertainty; a host of additional options are also envisioned for the near future including demand response (DR). There are well-established bodies of research that examine variable generation integration issues as well as demand response potential; but, the existing literature that provides a comparative assessment of the two neither treats this topic comprehensively nor in a highly integrated fashion. Thus, this paper seeks to address these missing pieces by considering the full range of opportunities and challenges for mass market DR rates and programs to support integration of variable renewable generation.

1. Introduction

The penetration of wind and solar generating resources is expected to dramatically increase in the United States (U.S.) over the coming years. 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). Due in part to these policies, near term (2020) projections by the Energy Information Administration (EIA) (2011) and scenarios from DOE (2008) estimate 4-12% of annual electricity generation coming from the combination of wind and solar (based on 60-160 GW of nameplate capacity) in a future U.S. power system.

It is widely understood that large scale deployment of these types of renewable energy sources (e.g., wind, solar) that have variable and less predictable production characteristics than traditional thermal resources poses integration challenges for bulk power system operators (NERC, 2009).[1] The generation output from these resources varies with seasonal, diurnal, and synoptic weather patterns that are neither regular nor fully predictable, which will impact bulk power system operations (see Figure 1). The magnitude of this variability and uncertainty of output tends to be smaller over short-time scales (i.e., seconds to minutes) than over longer time scales (i.e., multiple hours and longer). For example, short-term forecast errors in wind production (i.e., less than 2 hour forecasts) lead to higher or lower wind generation than expected. To manage these short-term forecast errors, the power system operator either procures more or less imbalance energy from existing thermal generators. 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 larger forecast errors.

[1] Other renewable generation technologies, including biopower and geothermal do not present many of the same grid integration challenges as wind and solar. Waterpower technologies (e.g., ocean and hydrokinetic) do have variable output (e.g., significant ramps in output due to changing tides or ocean currents), but these changes are regular and rather predictable. See Sims et al (2011) for additional analysis of challenges in integrating waterpower vs. wind and solar resources.

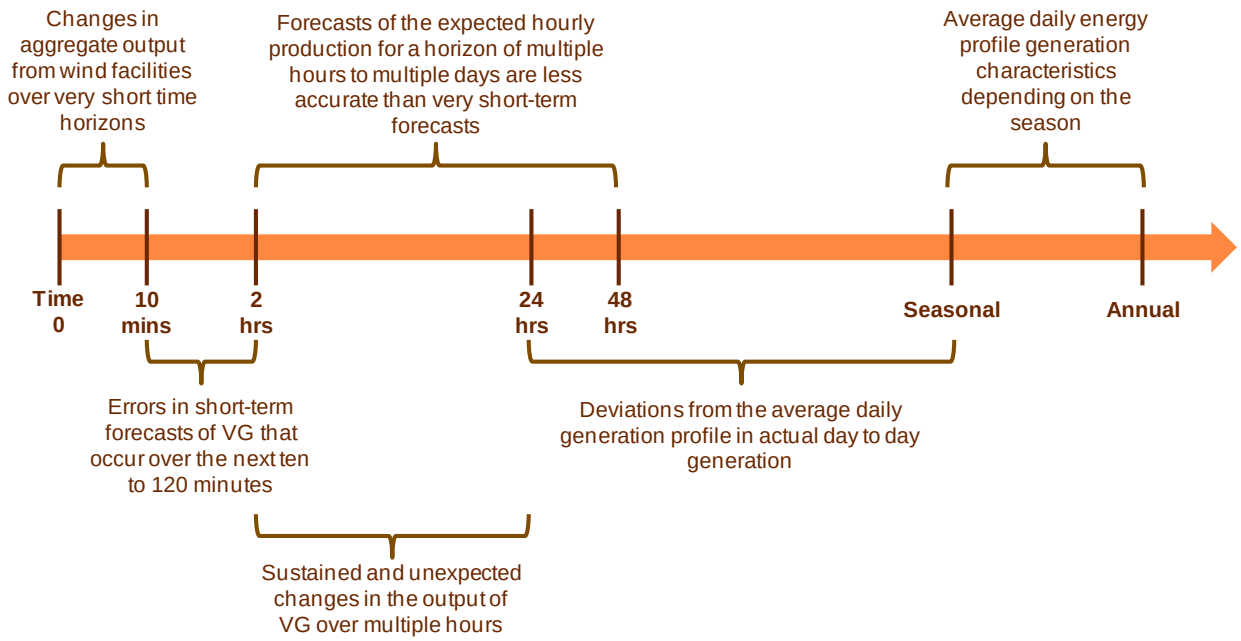

Figure 1. Variable generation (VG) production typology

At present, bulk power system operators primarily utilize strategies that rely on existing thermal generation resources and improved wind and solar energy production forecasts to manage this uncertainty; a host of additional options are also envisioned for the near future including demand response (DR).[2] In particular, 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 by expanding opportunities for demand response. By 2020, the electric power sector is expected to add ~65 million advanced meters[3] (which would reach ~47% of U.S. residential households) as part of smart grid and AMI[4] deployments (IEE, 2010). This investment will create the largest opportunity to engage and enlist a relatively untapped demand response resource: mass market (i.e., small commercial and residential) customers.[5] It is useful to develop an analytic framework that characterizes perceived risks, benefits and costs of various strategies (including demand response) which can be utilized to integrate larger volumes of wind and solar generation resources. As such, we believe the key question policymakers should be addressing is:

> *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*

[2] A more comprehensive description of these alternatives is contained in the larger report that serves as the foundation for this paper (Cappers et al., 2011).
[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."
[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).
[5] Most utilities have already installed interval meters for their medium to large commercial and industrial customers, who have been the target of demand response opportunities for several decades.

resources by providing mass market customers with greater access to demand response opportunities?

There are well-established bodies of research that examine variable generation integration issues as well as demand response potential; but, the existing literature that provides a comparative assessment of the two neither treats this topic comprehensively nor in a highly integrated fashion. In reviewing the literature, we found 12 studies that focus exclusively on how specific demand response opportunities can help manage specific variable generation integration issues that affect the bulk power system (see Table 1). These studies are informative but typically do not provide a comprehensive assessment of all types of DR opportunities, or do not consider barriers that limit the market potential of demand response resources, or incorporate the full range of variable generation integration issues.[6] As such, the applicability of the results of these studies to our key research question posed above is limited.

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	Calloway, 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, 2008
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

This paper seeks to address these missing pieces by considering the full range of opportunities and challenges for mass market DR rates and programs to support integration of variable renewable generation. Thus, to complement this existing literature, we believe it is imperative to[7]:

[6] For example, Calloway (2009) focuses exclusively on the role that DR programs targeted at ancillary services markets can play in affecting shorter-term VG integration issues, assuming there is a business case for load serving entities (LSEs) and/or Aggregators of Retail Customers (ARCs) to offer such programs. 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), assuming in the base case there is ample support by regulators and other policymakers for making such a rate design the default service for residential customers, but then assuming this rate would only be supported as default service for commercial and industrial customers in a sensitivity case .

[7] Our research reported herein focused primarily on policy issues that must be resolved for demand response to manage variable generation integration issues. We did 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.

- Identify demand response opportunities for mass market customers enabled by the widespread deployment of AMI systems and their potential to affect the bulk power system; and
- 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 more readily achieve this potential for DR to manage VG integration issues over the longer term.

This paper is organized as follows. First, we examine which demand response opportunities could be feasibly relied on to integrate large amounts of wind and solar resources in the bulk power system. Next, we identify the entities and institutions that would need to be involved in linking end-use customers and variable generation resources. Then, we discuss various near-term activities that will substantially affect the level of penetration of these mass market DR opportunities thereby illustrating some of the barriers standing in the way of DR serving as a viable resource to manage VG integration issues.

2. Near-term Mass Market DR Opportunities for Managing VG Integration Issues

This section develops a typology of the various rates and DR program opportunities for mass market customers and then discusses the roles each could play in managing specific VG integration issues. We focus exclusively on the capabilities and potential inherent in the offered rate or program.

2.1 Typology of DR Opportunities:

Several different typologies have been developed over the years to categorize demand response opportunities offered to end-use customers by Load Serving Entities (LSE) or Aggregators of Retail Customers (ARC). The Federal Energy Regulatory Commission (FERC), starting in 2006, began an effort to annually assess the entities offering demand response opportunities, enrollment levels, and peak load reductions by surveying all entities offering such rates and programs. Consistent with typology utilized by FERC in its latest assessment (FERC, 2011a), we categorize the current suite of demand response opportunities offered in the U.S. by the type of DR signal used to elicit a change in a customer's consumption of electricity: time-based retail rates and incentive-based retail programs.[8]

Time-based retail rates all assume that customers will alter their consumption of electricity in response to changes in its pricing or their resultant affect on bills. *Time of use pricing* (TOU) rates provide different but fixed prices over specified periods of the day and week which may vary by season (e.g., higher price during summer weekdays between 12 noon and 6 PM vs. discounted price during off-peak and weekend hours). *Critical peak pricing* (CPP) rates institute a single pre-determined price or sometimes variable price schedules during a narrowly defined period (e.g., customers are charged a higher price during summer weekdays 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. Customers receive billing credits at a pre-determined rebate price by reducing usage during critical hours and only for consumption below a pre-established level of electricity consumption (i.e., a customer specific baseline); all other consumption is priced at the otherwise applicable tariff rate.[9] *Real time pricing* (RTP) represents a rate schedule where the price can differ on a daily basis 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 (day-ahead real time pricing or DA-RTP) and another that provides the hourly price

[8] Table 2 portrays the different demand response opportunities as independent. However, in theory and practice, different DR opportunities may be combined as shown in FERC (2011a) (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 incentive-based 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 (see EPRI, 2011).

[9] 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 as described in FERC (2011a), we have opted to classify CPR as a retail rate.

within 60 minutes after consumption has already occurred (real-time real-time pricing or RT-RTP).[10]

Incentive-based retail DR programs 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 automatically by the utility, and now by the independent system operator Electric Reliability Council of Texas, Inc. (ERCOT), if warranted due to bulk power system conditions. *Emergency DR resource* programs usually provide load reductions to the bulk power system when grid conditions are expected to or have already begun 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.

All forms of demand response anticipate that either the utility will directly control end uses (i.e., 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 DR signal changes (e.g., ten times per year) that can occur during a year, the time interval between these signal changes (e.g., daily, multiple times within a day, no more than 3 days in a row), the advance notification period (e.g., less than 1 minute, 10-30 minutes, 2 hours) of a signal change, and the maximum duration before the DR signal changes again will all dictate the ability of the LSE or ARC to direct the commencement and duration of changes in end-use customer consumption. Table 2 summarizes the time scale of

[10] 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).

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 rates and programs where the length of advance notice is very short (i.e., seconds to minutes), mass market customers will need to rely on automation and control technology which will likely have implications for customers' ability to alter consumption patterns and their willingness to participate in the rate or program.

The full range of demand response opportunities offered today and in the near future assumes that 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).[11] There may be some concerns that many mass market customers will be unwilling, if not unable, to curtail loads over long time periods (e.g., greater than 6 hours). 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 and control technology (e.g., programmable communicating thermostat that directly controls air conditioning load).

Demand response impacts and acceptance can also vary in terms of how frequently customer consumption is expected to vary. This "frequency of response" is a function of both how fine the signaling periods are but also how frequently those signals change across periods. If the LSE/ARC provides signals to alter consumption on a concentrated and frequent basis (e.g., ancillary services programs), such variability generates concerns about fatigue in mass market customer performance. For example, Eto et al. (2007) illustrates that customers with simple direct load control devices on heating, ventilation and air conditioning (HVAC) systems are willing and able to respond to frequent DR signal changes with a very short duration absent serious customer complaints. In contrast, KEMA (2010) concluded that performance in Independent System Operator New England, Inc. (ISO-NE) Demand Response Reserves Pilot 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. 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.

[11] 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.

Demand Response Opportunity	Time Scale		
	Advance Notice of Response	**Duration of Response**	**Frequency of Response**
Time-Based Retail Rates			
Time-of-Use	> 6 months	Length of peak period (e.g., ~4-15 hrs.)	Daily, seasonal, etc.
Critical Peak Pricing/Rebate	2 – 24 hrs.	Length of critical peak period (e.g., ~2-8 hrs.)	Typically <100 hrs/year
Day-ahead Real Time Pricing	~24 hrs.	Depends on price level (e.g., ~2-8 hrs.)	Depends on price level
Real-time Real Time Pricing	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 2. Current demand response opportunities

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. However, the type of bulk power system service that could be provided is dependent upon how amenable characteristics of the DR signal that is given to a participating customer (i.e., advance notice, duration, and frequency of the DR signal change as illustrated in Table 2). Thus, these DR signal characteristics will, in turn, dictate the efficacy of each DR opportunity in managing the various integration challenges posed by increased penetration of variable generation resources, as described in Figure 1. The next two sections focus on assessing the role each of the two types of DR opportunities could play in affecting VG integration issues.

2.2 Opportunities for Time-Based Rates to Affect VG Integration Issues

Time-based rates, as currently defined, designed and offered in the U.S., have limited opportunities to affect integration issues associated with increased penetrations of variable generation resources because they generally lack sufficient granularity in the prices shown to customers to reflect contemporaneous system conditions and costs. Customer acceptance of both rate designs that change frequently and without much, if any, advance notification as well as automation and control technology to respond accordingly to these fast changing DR signals will determine the efficacy of these DR opportunities in managing variable generation integration issues.

A key challenge with relying on mass market customer response to currently designed time-based retail rates as an option for managing variable generation integration issues is that the DR price signals from most rate designs are not highly time differentiated. For example, nearly all time-based retail rates currently 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 (e.g., 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 offered to mass market customers.

Moreover, only a subset of time-based retail rates is capable of reflecting contemporaneous 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 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 existing 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 other than RT-RTP, as currently offered and designed in the U.S., would have a very limited opportunity to manage variable generation issues (see Table 3). Even if the price signals were enhanced to be more reflective of contemporaneous system conditions, mass market customers would likely 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 latency 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.

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

2.3 Opportunities for Incentive-Based Programs to Affect VG Integration Issues

Incentive-based DR programs would have significant potential to manage many variable generation integration issues if mass market customers are willing to participate in programs whose designs feature short duration and frequent demand response events. The efficacy of these DR programs in managing variable generation integration issues will be influenced by such factors as program rules that allow aggregations of customers to participate effectively and customer acceptance of control and/or automation technology. There is a rich history of direct load control programs across the U.S., especially at the mass market level, for which customer satisfaction is relatively high. For example, many utilities have implemented and maintained residential DLC programs that have achieved high market penetration rates over multi-year periods. These programs typically rely on controlling air conditioning or hot water system loads or other large electricity consuming devices (e.g., swimming pool pumps) that operate coincident with system peak periods, which often occur only a few days in the summer or winter. Some DLC programs (e.g. water heating) can provide load reductions throughout the year and 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 4).

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 typically requires fast response to changes in the DR signal nor are they dispatched frequently (e.g., 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 4) – and have not historically been targeted to the mass market customer base.

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., air conditioning, swimming pool pumps) would be unable 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, DR program providers would need to supplement these resources with others or system operators would need to alter the ancillary service product definitions or product requirements.

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 likely be feasible only with substantial reliance on control and/or automation technology. As with time-based retail rates, 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 incentive-based 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 policies.

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

3. Influential Near-Term Activities Affecting Penetration of Mass Market DR Opportunities

In this section, we identify several near-term activities and influential entities and institutions that will substantially affect the level of penetration of these mass market DR opportunities. We describe the role that existing market and regulatory institutions play in facilitating participation by demand response resources and then highlight the role of advanced metering infrastructure as an enabling technology for mass market customers. We also discuss the potential role of alternative service delivery models in enhancing customer acceptance of other enabling technologies.

3.1 Role of Existing Market and Regulatory Institutions in Overcoming Barriers to Demand Response

To determine the role demand response could play in helping to manage integration issues associated with increased penetration of variable generation resources, we must understand key entities and institutions that link mass market customers' consumption of electricity to variable generation resources' production of electricity. In particular, we must understand whether the linkage can generate sufficient value for all parties involved.

As illustrated in Figure 2, retail entities, specifically LSEs and ARCs, harness the demand response capabilities 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 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 and approved by federal regulators.

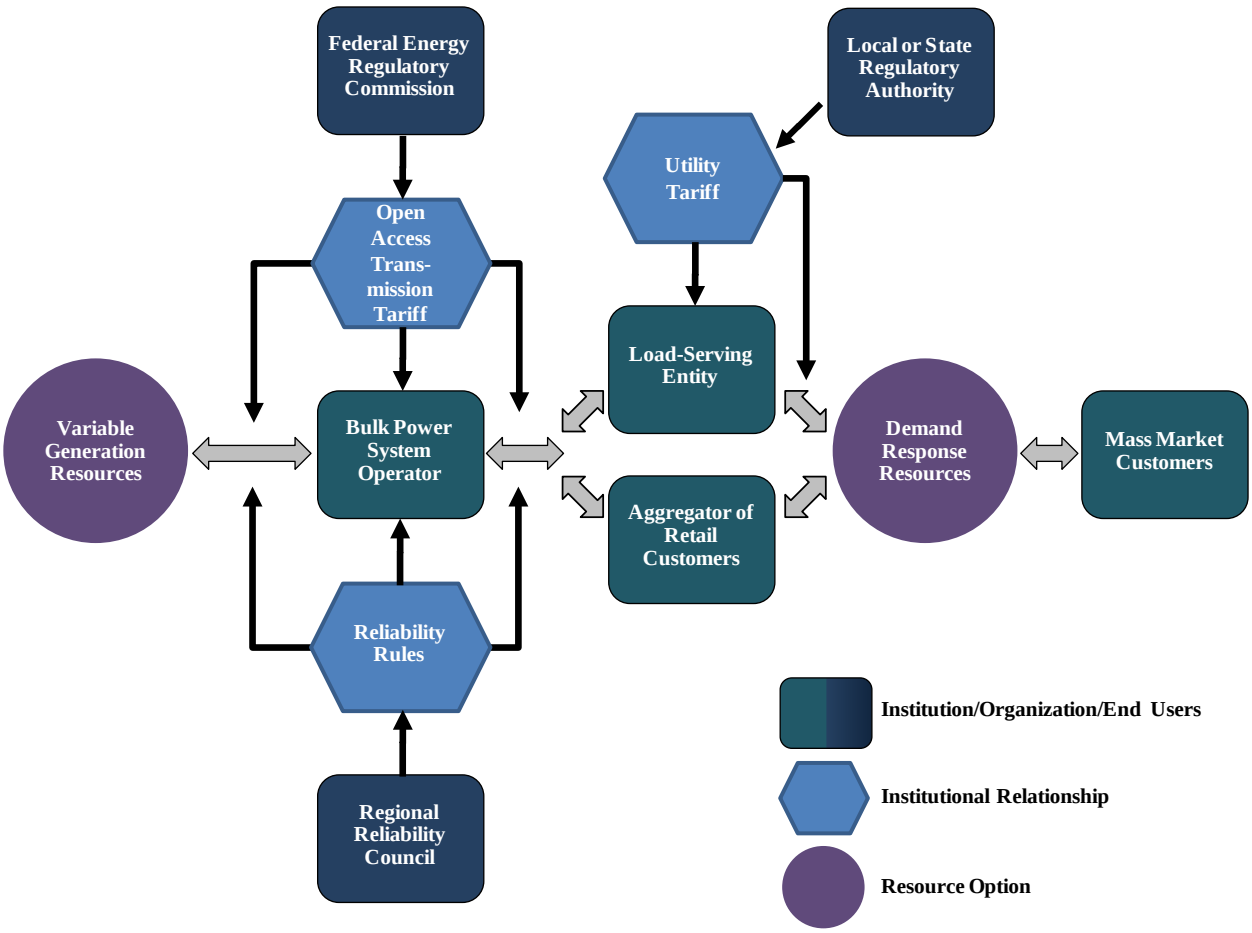

Figure 2. Entities and Institutions that influence the relationship between VG and DR resources

Existing rules for wholesale markets and reliability requirements were initially designed and subsequently evolved under a "generator-only" supply-side paradigm. In many jurisdictions this meant generators were explicitly identified as the sole providers of various bulk power system services or the rules were written in such a way that only a generator could meet the defined eligibility criteria. As such, these entities and institutions precluded, either explicitly or implicitly, DR resources from providing bulk power system services. Without changes to certain wholesale market tariffs and reliability rules, the value that could be created from DR resources providing bulk power system services by participating in various rates and programs would not be captured.

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 currently provide opportunities for demand response to provide spinning reserve and regulation services, while FERC Order 755 (FERC, 2011b) may be paving the way for expanded access to demand response resources who are able to provide frequency 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 were confident that aggregations of customers would behave comparably, both in terms of speed and predictability, to a supply-side resource.

In addition, definitions of bulk power system services could be altered to more widely access demand response resource along with other new resources like storage to provide existing or new ancillary services. For example, in most organized wholesale markets, the rules to provide balancing service requires resources to be capable of providing both balancing up and balancing down energy (i.e., the services are not separately defined). While it is possible for some loads (e.g., electric water heaters) 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 may inhibit participation and restrict access to those resources. Defining a separate balancing up from a balancing down service, as ERCOT has done, enables loads (along with other resources) which are capable of only providing unidirectional balancing service to still participate in such markets.

Even if DR is eligible to provide a variety of new or future bulk power system services, LSEs and ARCs must have the necessary support from other organizations to even offer such rates and programs that enable customers to provide such services. For example, 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, 2011a) 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.[12] At present, state regulators and stakeholders are more receptive to introducing CPP or CPR as a voluntary (i.e., opt-in) time-based rate in conjunction with their AMI deployment. CPP and CPR rate designs, as currently and commonly designed, do not provide a substantial ability to manage variable generation integration issues (see Table 3).

DR service providers, if given the necessary support by stakeholders and policymakers to pursue these various kinds of DR opportunities, must be able to extract some sort of value from their creation and implementation if they are to be expected to pursue these opportunities on their own. Absent regulatory or legislative fiat, there must be a sufficient business case for utilities or third-party providers to incur the cost of developing, marketing and subscribing customers to these DR opportunities. It remains to be seen if such a business case can be constructed for all entities in all retail/wholesale market jurisdictions or if the value proposition only holds under certain conditions for certain classes of customers with certain types of end-uses.

Lastly, the opportunities created by the DR service providers must generate sufficient value to customers or else they will eschew these offerings. Rate discounts, direct payments and/or lower bills have all historically been used to effectively market various DR rates and programs. In this

[12] The U.S. Department of Energy's Funding Opportunity Announcement for its $3.5B Smart Grid Investment Grant program included requests for grant recipients to propose pilots that would mimic the roll out of real-time pricing as default service. Not a single grantee pursued this option (see smartgrid.gov for more information).

case, both the direct (e.g., telemetry, communications, etc.) and indirect (e.g., inconvenience of more frequent events) costs associated with providing these kinds of ancillary services may necessitate a greater payment, piggy-backing participation with other offerings (i.e., capacity programs) or other (more novel) methods for eliciting customer participation.

3.2 AMI Deployment

If the business case for DR service providers to offer these DR opportunities to mass market customers can be made, the scope of deployment of advanced meters with two-way communication capabilities to mass-market customers will dictate which customers are even eligible for participation in many of these DR opportunities. 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 an 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). Given the limited experience with such meter deployment approaches, opt-out rates for advanced meters are not known at this time. This makes it more challenging to predict the eligible population for DR opportunities.

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. Thus, to respond to these concerns, Baltimore Gas and Electric amended its filing to make participation in a time-of-use rate voluntary.

3.3 Acceptance of "Smart" Technology through Alternative Delivery Mechanisms

As mentioned above, many of the VG integration issues can only be addressed by demand response resources with the direct use of automation and/or control technology. The extent to which such technology will be provided as part of a utility's AMI roll-out is unclear, as is whether customers would 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 for DR program and technology equipment/service delivery.

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 DR program 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) 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 (NIST, 2011).

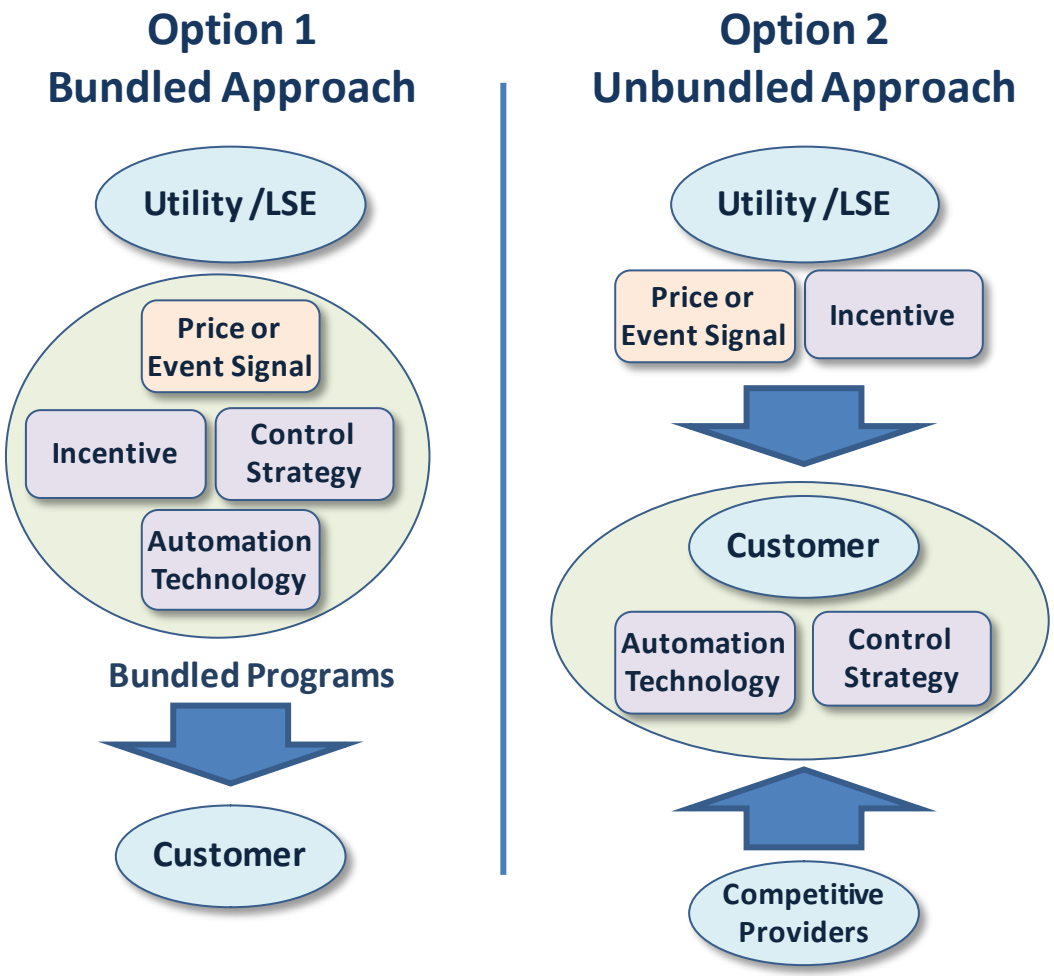

Figure 3. Automation and control technology implementation options

As a practical matter, customer acceptance of time-based retail rates and incentive-based DR programs intended to help in managing variable generation integration issues is intertwined with their acceptance of control and automation technology. The concerns raised by customers and their agents in various venues across the country (see for example 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 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 (i.e., calculation of customer electricity bills under alternative rate designs), incentives and rebates for enabling technology, and training/information can all be utilized to help address customer acceptance issues. Rigorous evaluations of AMI deployments that test various combinations of time-based pricing options, control technology and customer education, information, and behavior strategies are essential if utilities are to meet this challenge successfully.

4. Conclusions

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 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 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, including demand response. This paper focuses on identifying and assessing the role that various AMI-enabled mass market demand response opportunities can play in helping to manage these integration issues, as well as the challenges that must be addressed if they are to play this role.

We find that real-time pricing coupled with automation/control technology, have the greatest potential of all time-based retail rates to address the largest number of variable generation integration issues. However, to achieve this potential requires garnering increased regulatory and stakeholder support for transitioning mass market customers onto these rate designs.

We also find that 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 will need to establish response strategies that rely on control and automation technology to provide the necessary load curtailments. Customer acceptance of control and/or automation technology through carefully designed marketing and education efforts is, therefore, 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 either incentive-based programs or time-based rates is intertwined with their acceptance of control and automation technology. To facilitate this acceptance, technology implementation would likely need 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, we suggest that an alternative approach 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 mass market customer demand to facilitate integration of large-scale variable generation will likely require additional changes in market rules and regulatory policies. For example, changes to reliability rules should be considered that allow demand response 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 (and other new resource types) 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 markets (e.g., intra-hour markets in the West). Ultimately, the preferred portfolio of strategies for managing variable generation integration issues will be influenced by the relative costs, benefits and perceived risks of these various strategies. Comprehensive assessments and systematic analysis of risks, costs and benefits of various DR and non-DR strategies should be an area for future research. We expect that bulk power system operators may end up managing variable generation integration issues by utilizing a varying mix of strategies in their portfolio, which may be driven in part by differences across regions and power systems in system operating characteristics, generation mix, load and a host of other dynamics that directly influence the specific integration issues each system operator needs to solve.

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