

## White Paper

### **Creating A Regulatory Framework For Demand-Side Investment In The Distribution Grid Equivalent To Capital Investment in Generation**

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#### **I. Introduction**

For more than a century, the regulatory compact between electric utilities and the public has ensured reliable electricity service at just and reasonable rates. Working within this compact, regulators have developed ratemaking frameworks that balance customers' desire to keep electricity affordable with utilities' need for capital investment in their systems. Regulators around the world have successfully used the regulatory compact for the economic regulation of electric utilities, both where their state or country employs a traditional utility model and where electric utilities have restructured. But some regulators and utilities have begun to question whether the regulatory compact is robust enough to handle the new challenges facing the world's electric systems.

The problems confronting the electric systems of the world today are many. They include aging infrastructure, inadequate resilience of the distribution grid in extreme weather conditions, increased environmental controls, peaky demand profiles and capacity shortages in countries with growing economies. Increasingly, utilities worry that they will be unable to make the investments needed to address these problems while upholding the regulatory compact's obligation of safe, reliable and universal service at an affordable cost. However, the recent global revolution in telecommunications, analytics and computing has helped produce advanced, affordable distributed energy resources (generation, storage and renewables) (DER), as well as fully automated demand-side management (ADSM) systems to help balance the DER. These new technologies present their own challenges, but they also offer solutions and opportunities for utilities, regulators and the public.

The purpose of this paper is to show how regulators, working within the regulatory compact, can enable stand-alone or integrated distribution utilities to invest in ADSM and incorporate DER as an integral part of the utility's resource portfolio. ADSM can help regulators, consumers and utilities realize a safer, cleaner, more affordable and reliable electric system by balancing DER and unlocking capacity at the edge of the grid. As we explain, there are no rulemakings or significant policy changes required: only minor adjustments to the existing regulatory framework are needed to align the interests of diverse stakeholders and support investment in new edge-of-grid technologies.

This paper focuses on the distribution level of the grid.<sup>1</sup> In Section II, we provide an overview of demand-side management (DSM) over the last 30 years and explain why its potential to be a valuable tool in the

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<sup>1</sup> This paper is an update of our prior white paper, which presented a high-level outline of a regulatory framework for handling generation-quality ADSM technologies in the context of a vertically integrated utility, but did not consider how to apply the model in jurisdictions that have restructured their energy markets. As a result, we received many

distribution utility's portfolio has never been realized. We then describe ADSM technology and explain how and why it provides the value that previous DSM models never could. We show how ADSM also provides a platform for other edge-of-grid technologies, such as DER, that allow for coordination and optimal dispatch by the distribution utility. In Section III, we explain why previous approaches to DSM have been a poor fit for the traditional regulatory model and why this has hindered demand-side investment in new edge-of-grid technologies. Finally, in Section IV, we outline a flexible regulatory model for ADSM-as-capital-investment that we believe will help realign the varying interests of stakeholders while adhering to the existing principles of the regulatory compact.

## **II. DSM**

For decades, DSM has held out the promise of a reduced-emission, lower-cost, efficient alternative to the ever-increasing need for inexpensive, reliable power generation. Certain kinds of DSM can also bring added benefits to system operations, such as improving reliability and relieving congestion, and balancing the contributions of intermittent renewables by picking up the slack when the sun is not shining or the wind is not blowing. However, DSM has repeatedly failed to reach its potential, due both to disparate stakeholder interests and to technological limitations. ADSM, however, promises to elegantly balance the needs of regulators, utilities and customers while transcending the limitations of conventional DSM.

### **A. Conventional DSM**

While DSM has been a component of the utility and regulatory tool kit for more than 30 years, it has failed to become a reliable alternative to additional investment in generation and grid infrastructure. For example, in the United States, demand response (DR) programs are widespread, yet existing DR programs are dispatched nearly exclusively in “emergency” conditions as a last resort, and not as an integrated grid resource used, and useful, for day-to-day operations. There are a number of reasons that demand-side technology has thus far failed to live up to its potential.

First, regulated electricity providers in utility markets have hesitated to invest in DSM, because conventional DSM added expenses and eroded their revenues. These utilities would prefer to meet demand by investing in conventional generation that creates earnings, not expenses, while serving load. Conventional DSM poses difficult challenges for regulators, because the “demand product” is reduced consumption of electricity (i.e., “negawatts”), rather than something the utility can sell to the consumer. For utilities, conventional DSM has provided no investment potential; regulators usually allow them to “break even” and recover their costs, but not to earn a return on DSM investments. Likewise, regulators have failed to adopt a ratemaking methodology that recognizes the “negawatt” reduced as an equivalent to the megawatt produced by traditional generation resources.

Second, there is genuine confusion as to what benefits demand-side technology can provide. Typically, discussion of DSM products lumps diverse technologies together. In reality, DSM includes a range of products, such as simple phone calls and radio ads imploring consumers to conserve, consumer-

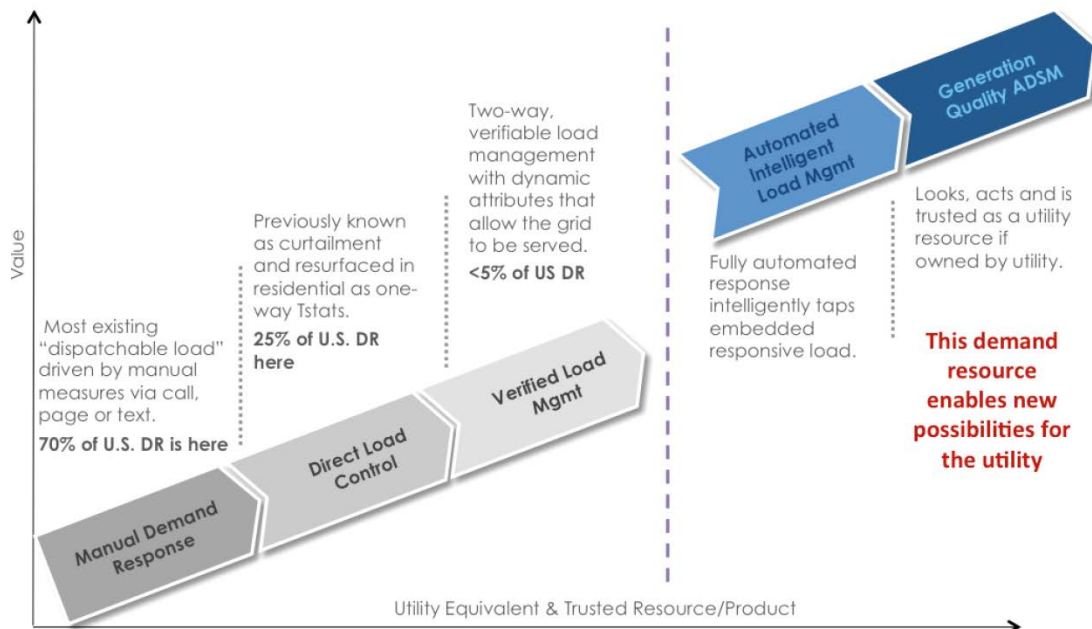
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inquiries as to how the model could be applied in those jurisdictions where load-serving utilities have divested generation and now own only distribution assets. This white paper responds to those questions, as well as to comments we have received from regulators in a number of jurisdictions.

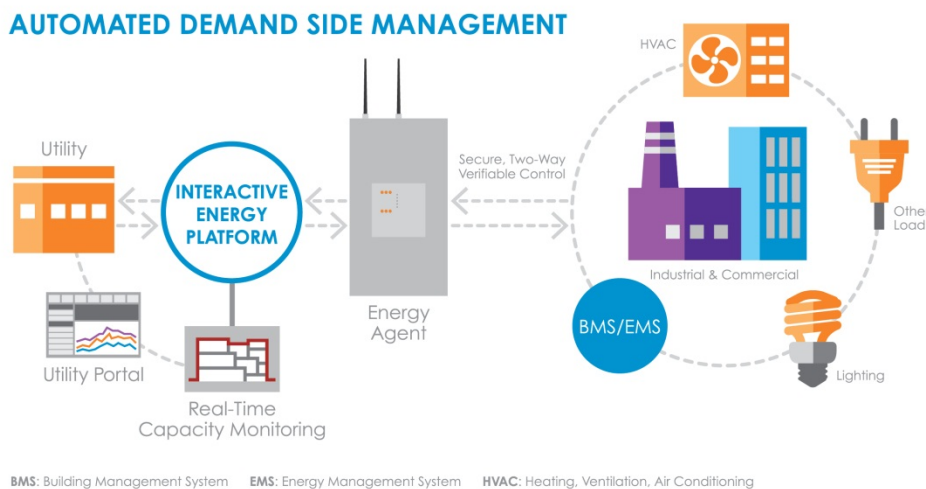
controlled energy efficiency improvements and DR aggregation. Today, newer technologies are providing two-way automated, verifiable load management systems, such as ADSM, which can be optimally dispatched by utilities to enable a variety of intermittent renewable resources, as well as other edge-of-grid technologies. Although all of these DSM technologies operate primarily to manage system load, they differ greatly in how they do so and the degree to which their impacts can be controlled, verified and fine-tuned; thus, their benefits to the electric system and “usability” by the system operators also differ greatly. It is important to understand clearly the differences between these DSM solutions and not lump them together into a single class of resources.

## B. Automated DSM

Unlike most DSM solutions, ADSM is not a “service” or “program,” but rather a networked monitoring-and-control system of physical assets that is suitable for inclusion in a utility’s rate base as a capital asset. ADSM harnesses modern computer and communications technology and sophisticated algorithms to create and manage a network of demand-side resources that the utility can dispatch, either individually or collectively, with a high degree of visibility, reliability and granular control. ADSM is directly dispatchable and verifiable from the utility control room, allowing a utility to make incremental changes in end-use customer demand; balance renewable energy resources; integrate other active resources, such as distributed generators and energy storage systems; and verify these control actions in real time.



Because of the level of control and verification that it provides, ADSM offers the utility a way to turn all edge-of-grid resources into active participants in the operation and management of the distribution grid. To incorporate ADSM into the distribution grid, the utility works with its participating customers to install utility-owned<sup>2</sup> monitoring-and-control devices on or near customers' premises, and operates communication and control systems to integrate the entire network of edge-of-grid resources. These control devices are connected to multiple-capacity resources, including end-use, energy-consuming appliances at each host site, such as lighting and HVAC. Control devices can also be connected to distributed generation, DER or energy storage, either as customer-owned or utility-owned assets. The contract with the customer allows the customer to define the operating parameters for its resources, specifying how much or how little, and when, its end uses can be dispatched; how much of its generation or storage is available for dispatch; and for what reasons. ASDM is unique in that it, for the first time, aligns the customer's operating parameters with the needs of the utility and coordinates between the two for optimal dispatch.



An ADSM system is made up of hundreds or thousands of individual customer resources, all linked by their control devices to the utility's network operations center (NOC). Because the control devices provide two-way communications, the control signal and the change in energy use can be immediately verified, and resources managed with precision. Although the dispatch of any given resource is defined by the customer's operating parameters, the ADSM system reliably integrates a large number of resources to deliver fine-grained control over the area of the distribution grid where the resources are located, allowing the utility to dispatch ADSM resources in significant blocks of kilowatt- or megawatt-equivalents.<sup>3</sup>

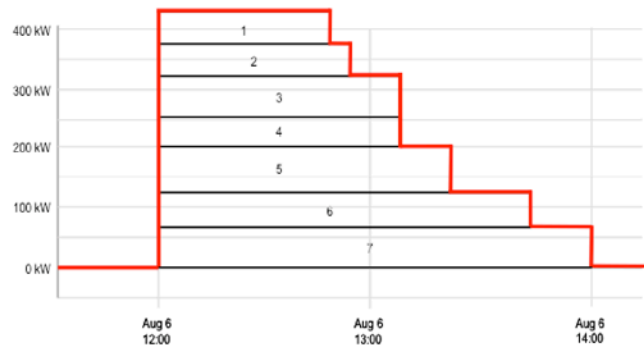
<sup>2</sup> We assume that the utility would own the control devices, other arrangements are possible. The endpoint devices could also be purchased by others, yet conform to the control system and communication requirements of the utility that is still operating the balance of the system to the benefit of the electrical grid.

<sup>3</sup> Moreover, because ADSM dispatch is under the utility's direct control, the utility avoids the risk that an aggregator may activate load drops that could harm grid stability.

Advanced algorithms incorporated into the ADSM system allow the operator to select among a diverse portfolio of resources to manage load when and where it is needed (i.e., dispatching capacity on a single feeder to accommodate operational constraints), thus improving grid stability and reliability. Because of these same characteristics, ADSM is reliable and available for hundreds or thousands of hours each year, allowing it to become part of day-to-day grid operations and improve the utilization of the electrical grid.

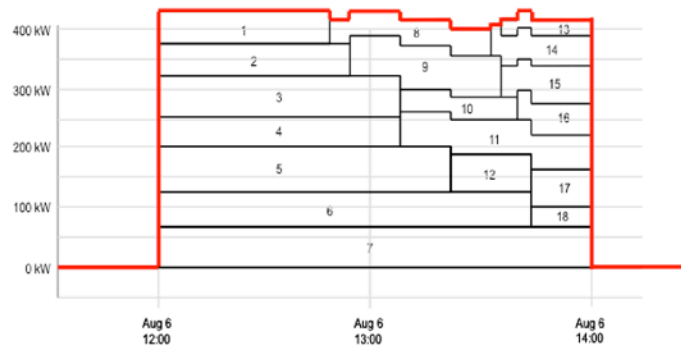
### Old Demand Response:

- Capacity uncertainty.
- Stretching participation can lead to customer dissatisfaction, and performance penalties.



### Real-Time Verifiable Capacity through ADSM:

- Capacity certainty.
- Manages site based on real time information and learned site capability.
- IEP selects a combination of devices, each represented by a "brick" (capacity and duration), which are stacked and sequenced to meet the dispatch request.



Unique capacity profiles are represented by dispatch "bricks," which are stacked and sequenced to meet the dispatch request. Each brick represents the unique capacity (height of brick associated with the Y axis) and duration of control capability (length of brick associated with the X axis).

By operating all its ADSM resources in real time, the utility can better manage, even shape, its load duration curve. In short, ADSM technology allows utilities to dispatch edge-of-grid resources as reliably as generation, managing the resources on the grid to produce “negawatts” that are functionally the same as the megawatts produced by conventional, gas-fired generation. An ADSM system can also be used to balance and integrate DER resources, including distributed generation and storage. The utility can choose to operate its ADSM system as a virtual peaking power plant, a grid management system, a grid power balancing system or a combination of utility operating objectives. In fact, because of their flexibility, the same ADSM resources can provide multiple system benefits, including providing ancillary services, relieving congestion, balancing renewable generation, reducing line loss, and contributing information to outage management and restoration systems.<sup>4</sup>

### **III. The Ratemaking Challenges of Conventional DSM**

Utility ratemaking involves balancing a number of potentially conflicting goals, among which are the attraction of capital, the provision of reasonably priced energy, and influencing demand.<sup>5</sup> By its nature, DSM furthers the goal of influencing demand. However, balancing the remaining ratemaking goals has been a challenge for regulators wishing to promote DSM. In particular, it has been challenging to figure out how to compensate the incumbent utility and encourage DSM investment effectively.

Ratemaking under the regulatory compact incentivizes utilities to produce electricity at affordable rates by rewarding their investment in the assets necessary to generate it.<sup>6</sup> Conventional DSM does not fit well within this regulatory structure, because DSM does not contribute to increased production of electricity. DSM (and DER), instead, often cause a decrease in production of electricity by the utility. DSM also does not typically provide utilities with an opportunity for investment; any investment involved is usually made by a third-party provider, or perhaps by the customer itself—with the utility incurring the costs to manage the DSM program. The utility must then recover these costs, as well as its revenue requirement, while selling fewer kilowatt-hours overall. This fundamental mismatch between traditional ratemaking and conventional DSM goals has contributed significantly to the lagging implementation of DR. Not surprisingly, many utilities choose to invest in new generation to meet demand rather than turn to DR, even when new generation—particularly peaking power plants—is not the most desirable option in terms of cost, efficiency or environmental impact.

Some utility regulators, recognizing this problem, have designed various mechanisms to encourage utilities to offer DSM. These include true-up mechanisms to reimburse the utility for its DSM program costs, with provisions for a small percentage reward (or penalty) for shareholders if the DSM achievements fall above or below prespecified performance levels. Another mechanism involves

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<sup>4</sup> By allowing distribution utilities to see and dispatch various edge-of-grid resources, ADSM provides a platform for the next generation of the grid, as conceived in New York’s *Reforming the Energy Vision* and other similar initiatives.

<sup>5</sup> See, e.g., JOSEPH P. TOMAIN & RICHARD D. CUDAHY, *ENERGY LAW IN A NUTSHELL* 123-128 (2004) (“Energy Nutshell”) (listing five goals: (1) the attraction of capital; (2) the provision of reasonably priced energy; (3) the creation of an efficient price; (4) the control of demand; and (5) management of monetary transfers between the utility and the customer base and among customer groups).

<sup>6</sup> See Appendix I for an overview of traditional, cost-based utility ratemaking.

“decoupling” the utility’s revenues from sales volume using “lost revenue payments.” The downside of these mechanisms is that they are developed in the context of a rate case, where such mechanisms are often particularly vulnerable, since they are often seen as a “bonus” to the utility, rather than as part of the utility’s basic compensation for providing electric service.<sup>7</sup> In addition, utilities worry that any gains they receive through such mechanisms will be more than offset by losses elsewhere. Finally, these mechanisms fail to provide utilities with the opportunity for earnings growth, and they therefore provide little incentive for the utility to proactively adopt and expand DSM services.

The underlying problem associated with these mechanisms is that they treat DSM as an “extra” service that is bolted onto the existing regulatory structure, rather than as an intrinsic and valued part of the grid infrastructure. This approach contributes to utility reluctance to invest in programs that might not be favored in their next rate cases due to a change in regulatory outlook or state administration. Additionally, DSM solutions that are imposed upon a utility—rather than embraced by the utility as part of the regulatory compact—fall short of making the utility a full partner in the development and deployment of demand-side technologies and consequently often limit their own success. If forced to adopt DSM, utilities often choose to invest in low-quality energy efficiency and DR solutions that allow the utility to meet its regulatory obligations, but provide only limited value to the public.

The deployment of demand-side services over the last 30 years has been constrained by the limits of older DR technology and poor interpretations of the regulatory compact. We believe that the regulatory model presented in this white paper, which treats ADSM as a capital investment, and an intrinsic and valued part of the grid, will align all stakeholder interests in support of demand-side solutions and enhance their deployment.

#### **IV. Ratemaking with ADSM as a Capital Asset**

As explained in Section II, ADSM provides new and improved performance and benefits comparable to new peaking generation or expanded distribution infrastructure. Moreover, ADSM is implemented using a physical, utility-owned and utility-maintained monitoring-and-control system that can, and should, be included in the rate base as capital assets. Below, we provide a framework that allows ADSM-associated costs to be treated as a capital asset for ratemaking and accounting purposes. We believe that this approach, which draws on the long-standing framework of the regulatory compact, will help to align the interests of regulators, utilities and customers to facilitate the adoption of ADSM technology, providing widespread economic, environmental and operational benefits.

##### **A. Regulatory Equivalence Between ADSM and Other Capital Investments**

ADSM should be treated as equivalent to other capital investments by regulators, because it provides comparable value, offering the reliability, security and predictability of a generation asset, but at a lower cost. For example, an ADSM system can be operated as a virtual peaking generation unit, allowing it to

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<sup>7</sup> This is particularly true because the average customer often fails to understand why a utility should be compensated for not producing electricity.

substitute for the construction of new gas-fired generation.<sup>8</sup> Notably, this does not only mean that an ADSM system can be used for peak shaving over a few peak hours of the year. ADSM also provides many of the other benefits of new gas-fired generation by operating reliably for hundreds of hours, making it available at times of operational constraint, which may not always be on the day of peak demand. In addition to load management, ADSM has a reliable and rapid response time, can be used to provide ancillary services and can be used to smooth the supply curve for intermittent renewables. Also, like any new resource, it can displace older, more expensive and less ecologically friendly alternatives.<sup>9</sup>

Additionally, ADSM monitors and controls individual resources to their precise location, including aggregating only those resources along one feeder or within the service area of one substation. With this visibility and granular control, ADSM can be dispatched to directly offset electrical constraints on a grid and defer costly capital improvement projects. Where traditional substation and feeder upgrades were once the only means to serve the growing demand of a community, now, by coordinating supply and demand, the utility can target ADSM installation as a direct offset to other capital projects.

## **B. ADSM Ratemaking**

Below, we outline a model for incorporating ADSM into a traditional ratemaking framework. In particular, we propose this model as a replacement to less desirable ratemaking solutions that rely on decoupling, true-ups and surcharges to balance the books. However, this model is not always “plug and play,” because different jurisdictions have implemented the regulatory compact in diverse ways appropriate to their circumstances. While some jurisdictions continue to receive electric service from vertically integrated utilities, others have, to varying degrees, restructured their electric sector. Therefore, we present the framework below more as a set of principles than as a complete accounting structure ready for immediate implementation in any given jurisdiction.<sup>10</sup> We explain how certain ADSM costs are analogous to other utility costs and suggest approaches that may be helpful in calculating charges for ADSM services, but we do not attempt to specify, for example, how ADSM costs should be allocated among different classes of customers. We encourage stakeholders in each jurisdiction to adapt and apply these principles in the way that is best suited to their own circumstances.

### **1. ADSM as a Capital Asset: CAPEX**

As explained above, ADSM provides benefits that are comparable to traditional utility capital investments. This includes specific improvements over prior DR technologies, which make an ADSM solution more reliable and useful to the utility system operator. Moreover, it includes hard assets that are suited for inclusion in a utility’s rate base in the same way that a new generation unit, generation control systems or new distribution infrastructure would be included in the rate base.

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<sup>8</sup> We chose a gas-fired generator for comparison, because gas-fired generators are now the industry standard for new generation, as shown by the decision of the organized markets to use gas-fired units to set the Cost of New Entry in their markets.

<sup>9</sup> A further discussion of the economic benefits provided by ADSM, and how ADSM can be treated within the integrated resource planning process (IRP), can be found at Appendix II.

<sup>10</sup> In our prior white paper, we presented a regulatory framework that treated ADSM as peaking generation for ratemaking purposes. However, even in jurisdictions with vertically integrated utilities, this approach can be unnecessarily rigid.



There are two categories of assets associated with ADSM that are suitable for rate-base treatment. First are the ADSM control devices that are installed on, or near, the customer premises. These devices are physical, utility-owned assets, which are part of a secure control system hosted by the utility. Utility accounting principles allow for utility-owned assets installed on customer premises to be included in the rate base.<sup>11</sup> Similarly, the installation costs of these assets should be included in the rate base.<sup>12</sup> Second, utility accounting principles also provide for the inclusion of computer hardware and software in the rate base, along with the installation costs of those computer assets.<sup>13</sup> Therefore, the costs of creating the ADSM network and establishing the NOC are treated as a capital asset under standard utility accounting principles.

The rate-base treatment of utility control devices and software is far from novel. Today, utilities install as capital assets supervisory control and data acquisition (SCADA) systems, which are monitoring-and-control systems to the substation level that are hosted by a utility NOC. Likewise included in rate base are distribution automation systems, which control field equipment, include the elements of end devices and communication systems, and host computer systems to automate the functioning of utility equipment. ADSM is a secure monitoring-and-control system, which extends to the very edge of the grid and is served by a utility NOC, allowing integration with other utility operating systems and the balance between demand and supply of DERs. ADSM is therefore a natural extension to the operating infrastructure of the utility.

## **2. Operational Costs: OPEX**

The costs of operating, maintaining and dispatching the ADSM assets would be treated as an ordinary operating expense by the utility.<sup>14</sup> These costs are directly comparable to costs incurred in operating any other grid asset, so there is no need for ADSM-specific treatment for ratemaking purposes.

## **3. Variable Costs**

The majority of variable costs associated with ADSM would include incentive payments made to customers that agree to participate in a partnership with the utility and have ADSM control devices installed on their premises. These incentive payments are an industry practice established by DR to incent the customer to participate in programs that allow the utility to control the customer equipment. It is assumed that the “disturbance or inconvenience” caused by utility events must be compensated, and this

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<sup>11</sup> Under the FERC Uniform System of Accounts (USoA), equipment “on the customer’s side of a meter” is classified as a distribution plant under Account 371, and it may be included in rate base if “the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property.” If the regulations of a given jurisdiction require that the utility lease these assets to the customer, or if that is the customer’s preference, the control devices can be accounted for under Account 372, which covers “Leased property on customer’s premises.”

<sup>12</sup> See Electric Plant instruction 9A.

<sup>13</sup> See USoA Accounts 382 and 383.

<sup>14</sup> Under the USoA, such operational expenses might be allocated to Account 556, “System control and load dispatching,” which relates to “load dispatching activities for system control,” or 581, “Load dispatching,” which relates to “load dispatching operations pertaining to the distribution of electricity.” Maintenance costs could be allocated to Account 554, which covers costs for generation plants in service that are not specifically allocated to other accounts.

cost is assumed to be part of the ongoing costs to run the program. These incentives are paid only if the customer's assets are dispatched and if the customer does, in fact, participate (i.e., does not opt out of the event). In addition, customers that own other active resources, such as distributed generation, would need to be compensated to account for the operations, maintenance and fuel costs of their resources when those resources are dispatched for utility purposes.

Customer payments are a variable cost, because they are dependent on the terms of each customer agreement, the number of customer site agreements in place and how often a particular group of assets is dispatched. It is simpler to account for such variable costs through a periodic (usually monthly or quarterly) automatic adjustment mechanism, rather than waiting until the next rate case to true-up. In many cases, it may be simplest to account for these costs through an existing variable cost mechanism. For example, vertically integrated utilities might include customer payments in their fuel adjustment clause (since such payments are the “fuel” that makes ADSM “run”), while wires-only utilities might account for these costs through their generation cost mechanism.

In addition to incentive payments, customer payments may also include operations and maintenance costs and fuel costs for customer-owned distributed generation or storage that is incorporated into the ADSM system and dispatched by the utility. Under the ADSM model, customers that allow the utility to dispatch their privately owned resources for system purposes will be compensated for the costs incurred in doing so. However, the customers will be compensated for fuel and operational costs only when their assets are dispatched by the utility to benefit retail utility customers—not if they choose to continue to operate their resources for private goals, such as to save money when electric prices are high.<sup>15</sup>

The customer's fuel use during ADSM dispatch would be tracked and expensed by the utility into an adjustment clause. Likewise, the cost of maintenance on the customer's generation unit(s) would be split between the utility and the customer based on the ratio of the number of hours the unit was operated by the customer to the number of hours it was dispatched by the utility. In other words, if the utility dispatched the customer's behind-the-meter generation unit for 300 hours, and the customer operated it independently for 100 hours, 75 percent of the costs of maintenance would be attributable to the utility and passed through its fuel adjustment clause. There are already many successful programs that use a similar process to allow the utility to partner with its customers to use customer-owned generation resources.<sup>16</sup>

This approach (i.e., treating customer payments as variable costs) permits these expenses to be passed through the utility's rates to customers in the same way as fuel or generation costs. As with a standard fuel adjustment clause, customer payments and fuel costs would be subject to true-up on a monthly or quarterly basis, allowing the utility more flexibility to adjust its rates to account for increases and decreases in these costs.

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<sup>15</sup> Customers would remain perfectly free to operate their resources for these reasons, but would not be compensated for doing so.

<sup>16</sup> See, e.g., Portland General Electric, *Dispatchable Standby Generator Program*, <https://www.portlandgeneral.com/business/get-paid-to-help-meet-demand/dispatchable-standby-generation> (last visited Feb. 8, 2016).

#### **4. Total kWh Dispatched**

The capital, operational and variable costs of ADSM all have equivalents to costs that are incurred by traditional utilities and, as discussed, can be treated similarly for ratemaking purposes. However, there is one additional accounting issue: the potential loss of revenue from forgone sales. A utility recovers its costs, and earns a return, through its rates. Customers are billed based on the kWh that they have consumed, at rates calculated to allow a utility to collect its revenue requirement for an expected volume of sales or distribution services. If that assumed volume of energy sales decreases, one of two things must happen: either the utility fails to recover its full revenue requirement, or the average cost per kWh must increase to cover the shortfall.

Because ADSM potentially decreases the number of kWh sold (or in the case of wires-only utilities, delivered) by the utility, it can pose difficulties for the traditional ratemaking model. The operation of ADSM improves the utilization of the entire system, rather than a single identifiable customer. Therefore, the cost of providing ADSM service should be recovered on a systemwide basis, because it provides widespread system benefits that should not be charged to any particular customer or class of customers. As discussed above, regulators have established decoupling mechanisms and lost revenue payments in an attempt to solve this problem. However, we believe that, in many cases, the lost-revenue problem can actually be addressed using a traditional ratemaking framework.

To deal with the lost-volume problem, two key adjustments need to be made to the traditional ratemaking paradigm. The first is to calculate the utility's rates based on kWh dispatched, rather than kWh sold or delivered. The second is to spread the total value of ADSM kWh dispatched across the entire customer base, because they are not attributable to particular customers, but rather benefit all customers. Together, these measures keep rates low, ensure utility recovery and prevent the cost burden from falling unequally on any particular group of customers.

##### **1. Rate Calculations**

ADSM can be incorporated into a utility's rates by setting the utility's average rates based on the kWh that the utility is expected to dispatch that year ("dkWh"), as opposed to the kWh that it is expected to be sold or delivered to consumers for consumption. Because ADSM dispatch is under utility control, it is possible to model and calculate, for a given year, the expected amount of load, in kWh, that will be negated by the use of ADSM ("ADSM kWh").<sup>17</sup> dkWh is calculated by adding ADSM kWh to the kWh that the utility is expected to sell or deliver pursuant to its rate schedules ("kWh sold").

$$\text{dkWh} = \text{kWh sold} + \text{ADSM kWh}$$

Once the dkWh is calculated, the utility's average price per kWh (i.e., its average rate) would be determined by dividing the utility's revenue requirement by its dkWh. In other words, the revenue requirement of the utility would remain the numerator for calculating average rates, but kWh dispatched would be in the denominator, rather than kWh sold.

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<sup>17</sup> As with a generator, if the "negawatts" fail to materialize when dispatched, there is no payment, and penalties could potentially be assessed.

Utility average price per kWh =	<u>Revenue Requirement</u> dkWh
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The use of this formula prevents utilities from losing revenue as a result of implementing demand-side solutions. A true up mechanism could be used to account for any variation between actual dispatch and the expected dispatch required for the utility's revenue requirement, just as such mechanisms are used when a utility's actual sales do not square with its expected sales. However, because this method accounts for ADSM dkWh, the mismatch between actual and expected kWh should be relatively small.

## **2. Revenue Recovery**

The use of dkWh to calculate the average price per kWh allows the utility to take ADSM into account when determining its average rates. However, although the utility's rates have now been adjusted to account for ADSM, the utility still needs to be able to recover its ADSM costs from its customers. Because ADSM benefits cannot be assigned to particular customers, the utility needs a mechanism for charging its customer base as a whole for the system benefits provided by ADSM.

To receive compensation for providing ADSM to its customers, the utility must determine the total value of the ADSM dkWh that it has dispatched. This value is calculated by multiplying the utility's average price per kWh by the number of ADSM kWh dispatched.

$$\text{Utility average price per kWh} \times \text{ADSM kWh} = \text{Total value of ADSM kWh}$$

Note that this approach means that the total value of the ADSM kWh is identical to the value to the utility of producing and selling, or delivering, an equivalent number of conventional kWh.

The utility can then recover the value of the ADSM kWh from all of the utility's customers through a surcharge or through other mechanisms allowed by the utility's tariff. Costs associated with other services that provide widespread benefits, such as transmission expansion, transmission line loss and the administrative costs of regional transmission organizations,<sup>18</sup> are socialized in a similar fashion (whether based on total energy or demand basis). Socializing costs on the basis of demand and including them in a distribution service charge would be one reasonable approach. Another viable approach includes folding the socialized cost into a generation charge.

## **5. Environmental Benefits**

Although not truly a part of ratemaking, utilities and regulators often take environmental effects into account when choosing among possible investments. We have included a discussion on resource planning with reference to ADSM in Appendix II. However, the benefits of ADSM with regard to environmental benefits deserves special note, particularly because of tightening restrictions on carbon emissions.

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<sup>18</sup> See, e.g., *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369-71 (D.C. Cir. 2004) (upholding the allocation of administrative costs to all users of a regional electric grid).

A “negawatt” is not presently recognized as a renewable resource (green tag), but offsetting generation capacity brings with it the reduction of generation plant emissions, which can be recognized as a “Carbon Credit,” “Carbon Allowance” or “Carbon Reduction Credit.” ADSM kWh can directly offset the generation capacity requirement for the region.<sup>19</sup> Therefore, ADSM kWh can be treated as an offset for the equivalent amount of carbon that would otherwise have been emitted using conventional generation to serve the same demand, based on the fuel mix of the region, and including any excess emissions specific to peak times when less efficient generators are in use. We propose that the utilities and regulators track ADSM kWh to calculate emission offset impacts. This will provide value in utility efforts to comply with environmental mandates. For example, ADSM kWh might be a useful tool that states can incorporate into their plans to meet the requirements for carbon emissions reductions from existing power plants that were recently finalized by the U.S. Environmental Protection Agency (EPA) in the Clean Power Plan.<sup>20</sup>

## **V. ADSM as an Integrated Utility Asset**

The structure described in this white paper allows ADSM assets to be treated as capital investments and accounted for in a traditional ratemaking structure in a way that encourages utilities to invest in demand-side options. Such treatment encourages utilities to think of ADSM as an option equal to investment in new generation or distribution assets and, furthermore, recognizes ADSM as an intrinsic part of the next generation of the grid.

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<sup>19</sup> However, if fossil-fuel, behind-the-meter generation is dispatched, those kWh could not be used as offsets.

<sup>20</sup> *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg. 64,662 (Oct. 23, 2015). In general, the EPA has provided wide latitude to states to include in their compliance plans any measures that they can demonstrate will result in verifiable emissions reductions from affected fossil-fuel, electric-generating units.

## Appendix I—Background: Ratemaking and Economics

Our model is anchored in traditional ratemaking principles and mirrors the methodology that regulators apply to a new peaking generation facility. Under this regulatory model, ADSM equipment installed at a customer's site, but owned by the utility, is included in rate base as a capital asset. The utility owns and controls this equipment and can produce “negawatts” as an alternative to dispatching additional generation. This equipment is operated and verified in real time, and can be dispatched as a “peaking plant” or for ancillary services.

### A. Revenue Requirement

Traditional ratemaking methodologies include a “revenue requirement” for the utility to recover through its rates. Calculating a utility's revenue requirement is a long and complicated process, but the central principles are illustrated in the following formula:

$$\mathbf{RR = RB (ROR) + Opex}$$

Where:

RR = Revenue Requirement

RB = Rate Base

ROR = Rate of Return

Opex = Operating Expenses<sup>21</sup>

A utility's capital investment is reflected in its rate base, which generally equals its prudently incurred, original capital costs for assets, less depreciation. Utilities typically earn a return on only assets included in the rate base, which is intended to encourage and support the needed capital investment to expand the utility's facilities and production.<sup>22</sup> Operating expenses (including the costs of its fuel and other power purchases net of sales) are also included in a utility's revenue requirement, but the utility does not earn a return on these costs.<sup>23</sup> Instead, these costs are passed through to customers and do not enhance the utility's profits.<sup>24</sup>

While some elements of conventional DR require limited utility investments in hardware and software, the bulk of conventional DR costs is for services that are categorized as operational expenses by standard utility accounting methods. The utility cannot include these as assets in its rate base and therefore cannot earn a return on providing DR services.

### B. Ratemaking

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<sup>21</sup> *Id.* at 130.

<sup>22</sup> *Id.* at 134, 136.

<sup>23</sup> *Id.* at 130-131.

<sup>24</sup> The recovery of operational expenses can contribute to profits if a utility becomes significantly more efficient between rate cases, but these efficiency gains are usually offset by cost increases for fuel or services.

Once a utility's revenue requirement has been established, rates for service are calculated that will allow the utility to meet its revenue requirement. Distilled to its essentials, this process calculates the price per kWh by dividing a utility's annual revenue requirement by the amount of energy (in kWh) that the utility is expected to produce and sell in a year.<sup>25</sup>

This is called the "throughput incentive," because it encourages the utility to sell more electricity, rather than less. Actual tariff rates for different classes of customers may differ, based on factors such as block-energy rates, demand charges and service charges.<sup>26</sup> However, the underlying structure sets rates so that the utility should recover its revenue requirement if it produces and sells the expected amount of electricity (supposing that the utility is prudently and effectively operating its business). If the utility sells less than the expected amount of electricity, then it will have to resort to a true-up mechanism to meet its revenue requirement, which can become a complicated and controversial process.

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<sup>25</sup> See James C. Bonbright, *Principles of Public Utility Rates* 306-314 (1961).

<sup>26</sup> *Id.*

## Appendix II—ADSM in the IRP Process

### A. IRP

A traditional utility is obligated to be able to serve customer demand across its entire service territory, whether by using its own generation resources, purchasing generation from others, or reducing and managing customer demand to the levels of available supply. The IRP process is designed to assess and compare options for serving load. Electrical infrastructure is complex, and modeling potential changes requires that hundreds of variables be calculated at any point in time. IRP uses an iterative process of changing only one option at a time and then evaluating the impact of that change. Changes in the location and level of load<sup>27</sup> on the electrical system requires assessing potential upgrade and expansion requirements across the utility's distribution, substation, transmission and generation systems, as well as considering wholesale purchase options. For example, installing new-generation capacity may require upgrades and expansions in transmission capacity, substation capacity and distribution capacity to deliver power from the new generator to end-use customers.

ADSM is designed to deliver demand-side capacity as reliably, and with the same capacity factor, as a peaking generator. Therefore, it can be evaluated within the IRP process as an equivalent and reliable capacity solution, defined with a clear, predictable, operational profile for energy and capacity delivery over the 8,760-hour year—just as a peaking power plant is analyzed. In contrast, conventional DR programs do not produce predictable results and are not dispatchable for hundreds of hours per year, or verifiable in real time, so their operational value to the utility is not considered even remotely equivalent to a peaking unit.

### B. Benefits of ADSM

When considering the costs and benefits of ADSM, it is important to compare all of the direct and indirect incremental value streams of ADSM and other resource options. Such a comparison would show, for example, that a conventional peaking generator may require transmission, substation and distribution upgrades, and that power delivery from that generator will incur electrical line losses. On the other hand, ADSM creates capacity at customers' premises, which directly offsets load and avoids both electric transmission and distribution infrastructure costs that would have been required for incremental generation, but can also defer or eliminate other "upgrade" projects in the network, as well as line losses. These offsets, avoided costs and incremental value streams are not always recognized in the IRP process, but are important in accounting for the true costs of comparable resources.

ADSM creates significant benefits to the system as a whole, many of which are outlined in Table 2

TABLE 2

Value elements for an ADSM project

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<sup>27</sup> This includes not only the impact of load increases, but also the impact of load reductions due to distributed generation behind the customer meter. Several states have recently experienced a doubling of solar photovoltaic (PV) installations and capacity every year with the decline in PV prices and the availability of new PV financing options.



Value Driver	Description
Generator Deferral	The financial value from deferring capital investments in peaking power generation plant capacity
Distributed Generators	The value of utilizing customer-owned capacity at the customer premises in lieu of utility-owned generation
Return on Assets	The value of the return on the asset at the allowed rate of return that the utility can earn on the ADSM project as a plant-in-service asset
Feeder Deferral	The value from targeted deployment and resulting deferral of capital investment in feeder upgrades by reducing or balancing the peak load on those feeders
Ancillary Services	The value from using ADSM for ancillary services (such as local voltage management and spinning reserve capacity)
Environmental Benefits	The value of environmental benefits, such as Carbon Dioxide Equivalent reductions, that result from the reduction in energy generation
Shoulder Month Savings	The value of shifting the seasonal start and stop times for incremental midstream generation, which runs during only the peak months
System Utilization	The value of improving throughput on the existing transmission and distribution assets while avoiding costly upgrades
Operating System Improvements	Reduced stress on electrical grid equipment, such as switched capacitor banks, voltage regulators and other operating devices, when balancing system performance
Avoided Power Purchase	The value of avoiding short-duration, spot-purchase energy prices when dispatching during peak load events
BMS Energy Efficiency Savings	The value of the energy savings realized by buildings that do not have a building management system (BMS) for utilities with energy efficiency incentives in place
Line Losses Avoided	Customer load reductions reduce the amount of electricity flowing across transmission and distribution assets and thus reduce line losses; line losses are disproportionately higher under peak loads, so peak demand reductions realize higher line-loss savings and free up more line capacity while avoiding more fuel burn
Substation Deferral	The value from targeted deployment and resulting deferral of substation upgrades by reducing peak load on those substations
Integration of Renewables	The value of balancing both distributed and central station intermittent renewables
Congestion Management	Because ADSM can be deployed on a feeder-specific or geographically specific basis, targeted load reductions can be used to manage and alleviate transmission congestion or facilitate scheduled or unscheduled facility maintenance
Outage and Restoration	Some ADSM designs offer feeder-level monitoring with “last-gasp capabilities” that can identify outages, enhance restoration efficiency and prevent unnecessary crew site visits
Distribution Engineering Tools	Power-quality monitoring, distribution-level PMU capability, voltage reference points on feeder for optimization of voltage conservation and digital fault recording