Creating A Regulatory Framework For Demand-Side Investment Equivalent To Generation & Grid Investments

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I. Introduction

Demand-side management (DSM) promises a reduced-emission, lower cost, efficient solution to the ever-increasing demand for reliable power, with added benefits to system operations and the integration of intermittent renewables, storage and distributed generation. However, as an alternative to additional investment in generation and grid infrastructure, DSM deployment has faltered. In the United States, for example, Demand Response (DR) programs are widespread, yet existing DR programs are employed nearly exclusively in "emergency" conditions as a last resort, and not as a structured grid resource.

One reason for this limited utilization is that vertically-integrated regulated utilities have hesitated to invest in DSM solutions that create expenses and erode revenue. While in a broader context the benefits of working on the demand-side are clear, conventional demand-side models do not contribute to the long-term support of a utility business. Regulated utilities recover their revenue requirement through their electricity rates, earning a return on the infrastructure that they own and operate. DSM poses unique ratemaking challenges because the "product" is reduced consumption of electricity ("negawatts").[1]

We believe that for DSM solutions to be successful over the long term, they must both serve the needs of the end-use customer and support the utility's business model. To date, we have not seen a model for demand-side products or programs that adequately addresses the needs of both the utility and the consumer in a manner that is also attractive to state regulators. This paper proposes a regulatory framework for a new demand-side product that is coming of age: fully automated demand-side technology (Automated Demand Side Management or ADSM). ADSM delivers a physical asset to the utility that is operationally equivalent to a peaking power plant. As such, we believe it could, and it should, receive regulatory treatment equal to a generation unit. We have applied traditional ratemaking principles to existing regulatory structures to create a compensation mechanism for ADSM that is a "regulatory equivalent" to that for peaking generation. We hope this modified regulatory model will encourage utilities to see improving demand-side resources as an alternative equivalent to supply-side options.

Not all DSM is the same and not all DR is the same. Although demand-side efforts have a long and rich history throughout the world, the past twenty years have resulted in dramatic technological advances in demand-side solutions. Debate about DR products often groups all products that reduce demand together, from simple phone calls and radio ads asking consumers to conserve, to two-way automated,

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[1] *See* "Negawatt Hour," *Economist*, Mar. 1, 2014, *available at* http://www.economist.com/news/business/21597922-energy-conservation-business-booming-negawatt-hour.

verifiable load management systems. But recognition of the distinct differences among these products would allow all of them to be used more effectively to maintain a reliable electric grid.

Table 1 illustrates some of the key differences between the characteristics and capabilities of a spectrum of DSM products, from manual DR measures to generation-quality ADSM. This comparison highlights the fact that different capabilities offer different impacts and benefits. The differences justify more favorable ratemaking treatment for those DSM products that offer greater benefits.

TABLE 1

NOT ALL DEMAND-SIDE MANAGEMENT IS THE SAME
Characteristics of Demand-Side Management Products

Legend:	○	◔	◑	◕	●
	No Benefit	→	→	→	**Greatest Benefits**

	MANUAL DR	DIRECT LOAD CONTROL	AUTOMATED DEMAND MANAGEMENT	GENERATION-QUALITY ADSM
Cost-effective	●	●	●	●
Enhances customer satisfaction	◑	◑	●	●
Can be dispatched specifically to geographic areas, Feeders, or individual loads	◑	◑	◕	●
Dispatch Verified with post-event settlement	◔	◑	●	●
Dispatch Verified with real time monitoring	○	◔	◔	●
Assets are installed within rate-base	○	◔	◔	●
Dispatch control and customer relationship directly managed by the host utility	○	○	◑	●
Customer can define and control operating parameters for their site	○	○	◑	●
Can be dispatched within minutes such as with Ancillary Services	○	○	◔	●
Permanent Load Shifting from peak demand to low usage times	○	○	◔	●
Can be operated repeatedly, in short durations, many times per year with little, or no, customer impact	○	○	◔	●
Integrates distributed renewables including on individual buildings	○	○	◔	●

Cyber Security to NERC CIP and utility standards including system interfaces	○	○	○	●

II. Automated Demand Side Management

Like other demand-side products, ADSM operates by controlling customers' electricity use when the utility or grid needs a change in total consumption. But ADSM has some attributes that other DR products lack. ADSM control devices are connected to multiple end-use appliances at each host site, such as lighting and HVAC. The control devices can operate each of those appliances, individually or in combination, with a high degree of granularity. Control is executed with two-way communications, so both the control signal and the change in energy use can be verified. Because ADSM is fully automated and precise, the customer can set limits on how much or little its various end-uses can be decreased, and for what reasons. With thousands of sites under automated control, the utility operator can activate an aggregate load decrease, or increase, with precision and instant effect.

ADSM creates "negawatts" that are operationally equivalent to megawatts for the utility, because the utility can dispatch either, or both, to meet the requirements of customers and the grid in the most reliable and economic fashion. ADSM can be dispatched directly by the utility operator from the control room as a cyber-secure resource that has the same immediate effect and operational interface as a peaking power plant. Unlike conventional DR, ADMS is available but throughout the day and year, rather than only in peak periods. Thus ADSM can create operational flexibility as well as verifiable energy and demand shifts. Because the utility can manage the ADSM asset directly, it avoids the risk that an aggregator may activate load drops that could harm grid stability.

The utility may also decide to use a contracted third party provider as an agent that acquires participating customers and installs the ADSM system and its operating hardware and software, but then allows the entire system and set of relationships to be managed by the utility. If the utility takes this approach, it can retain its direct relationship with the customer, rather than cede parts of that relationship to an intermediary. Many utilities have also experienced the situation where, if a third party serves as its DSM aggregator and operator, the utility has limited visibility and only indirect control over how or when DSM resources are deployed. This reduces the value of those resources for day-to-day, hour-to-hour grid management. Moreover, in regions with an active wholesale capacity market managed by a regional grid operator, DSM providers may activate load reductions to meet wholesale market calls without alerting or coordinating with the local utility, which can cause customer confusion and unintended consequences for the local system operator and their grid reliability.

III. Background: Ratemaking and Economics

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.[2] By its nature,

[2] *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).

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.

Most conventional DSM programs are managed by a third party provider, which must be compensated by the utility. With conventional DSM, the utility receives decreased sales and increased operational expenses that must be accounted for in its next rate case. Many utilities facing increasing demand have been reluctant to employ DSM programs as a substitute for new generation units that they can reliably manage and dispatch, and for which they are (usually) awarded a reasonable return on their investment.

This section briefly reviews the essentials of traditional cost-based ratemaking and the difficulties posed by conventional DSM inside that framework.

A. Revenue Requirement

A utility is obligated to maintain the assets and operational capacity required to meet peak demand. But, to remain in business, the utility must recover its costs, plus a reasonable rate of return on its investment. Traditional ratemaking methodologies permit a utility to earn its "revenue requirement" 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:

RR = RB (ROR) + Opex

Where:

RR = **R**evenue **R**equirement

RB = **R**ate **B**ase

ROR = **R**ate of **R**eturn

Opex = **O**perating **E**xpenses[3]

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 only on assets included in rate base, which is intended to encourage and support the needed capital investment to expand the utility's facilities and production.[4] 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

[3] *Id.* at 130.
[4] *Id.* at 134, 136.

return on these costs.[5] Instead, these costs are passed through to customers and do not enhance the utility's profits.[6]

While some elements of conventional demand response require limited utility investments in hardware and software, the bulk of conventional DR costs are 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 DSM service.

B. Ratemaking

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 kilowatt-hour ("kWh") by dividing a utility's annual revenue requirement by the amount of energy (in kWh) the utility is expected to produce and sell in a year.[7]

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.[8] 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.

Conventional DSM erodes utility revenues by decreasing the number of kWh produced and sold. Utility regulators have designed various mechanisms to encourage utilities to offer DSM and overcome the throughput incentive. These incentives include:

- Reimbursing the utility for its DSM program costs using a true-up mechanism, with a possible additional percentage reward (or penalty) for shareholders if the DSM achievements fall above or below pre-specified performance levels.

- Decoupling the utility's revenues from sales volume through such means as "lost revenue payments" or other true-up mechanisms to buffer revenues from lower kWh sales.

Whatever the DSM cost recovery mechanism, the utility offering DSM must rely on a true-up to reach its revenue requirement. And since most DR programs are dominated by operating costs (customer incentive and third party contractor payments) rather than capital costs, those costs can only be recovered through the utility's operating expense or fuel expense recovery mechanisms.

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[5] *Id.* at 130-131.

[6] 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.

[7] *See* JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 306-314 (1961).

[8] *Id.*

On the whole, traditional vertically-integrated utilities generally favor building new peaking generation facilities and associated delivery assets, on which they can earn a return, over pursuing demand-side options. However, new generation—particularly peaking power plants—is often not the most desirable option in terms of cost, efficiency, and environmental impact. Although attempts have been made to impose DR solutions by regulatory fiat, these attempts have attained only limited success.

The deployment of demand-side resources is now limited as much by conflicting interests as by technical limitations. Because it can be operated for hundreds of hours in a year, ADSM has the potential to become an integral part of utility resource planning, rather than an emergency resource or an afterthought. We hope that the regulatory structure presented in this paper will help align stakeholder interests in support of demand-side solutions by treating ADSM as a valuable asset that stakeholders in the energy value chain can gain value.

IV. Utility Investment

Most vertically-integrated utilities will only invest in assets that are approved by their regulator in advance. In many jurisdictions, the regulator requires the utility to make decisions as to how best to serve increased load through an Integrated Resource Planning (IRP) process, which evaluates potential means of meeting present and future demand considering safety, system reliability, infrastructure costs, and often environmental and portfolio flexibility needs. Such evaluations use complex cost-benefit models to determine which combinations of programs or additional assets will best meet the needs of the utility and its customers. Conventional DSM often fares poorly in an operations-dominated analysis because its use will generally be limited to emergencies.[9]

A. Integrated Resource Planning

A vertically-integrated 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 demands 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[10] 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.

[9] With the advent of mandated regional planning under Federal Energy Regulatory Commission ("FERC") Order 1000, which requires a systematic consideration of the ability of demand-side resources to help balance loads against supply, DSM resource options are being valued more highly.

[10] 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.

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 a reliable capacity solution, defined with a clear, predictable operational profile for energy and capacity delivery over the 8760-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 nor verifiable in real time, so their operational value to the utility is lower. Because they deliver little operational benefit, many utilities justify the adoption of DR and energy efficiency programs by recognizing additional sources of intrinsic value (for instance, emissions reduction, job creation, land use impacts avoided, and energy independence). A Total Resource Cost (TRC) test is often used for this purpose.

B. Total Value Model

Our proposed regulatory model allows, but does not require, the utility and regulator to incorporate a Total Value Model (TVM) as part of the overall IRP process. We believe the use of a TVM more accurately accounts for the full range of benefits offered by ADSM and easily integrates to the existing IRP process, unlike the TRC and other similar tests.

There are five cost-effectiveness tests commonly used across the country to assess the benefits of DR programs. Each of the tests provides a different kind of information about the impacts of a program from a different vantage point in the energy system:

- Total Resource Cost Test (TRC): Will the total costs of energy in the utility service territory decrease?
- Societal Cost Test (SCT): Is the utility, state, or nation better off as a whole?
- Participant Cost Test (PCT): Will the participants benefit over the life of the measure?
- Program Administrator Cost Test (PACT): Will utility bills increase?
- Ratepayer Impact Measure Test (RIM): Will utility rates increase?[11]

On its own, each test provides a single stakeholder perspective. Even if benefits outweigh costs, some stakeholders can be net winners and others net losers. None of these existing tests simultaneously capture all potential value streams, benefits and costs.

A TVM allows recognition and comparison of all the direct and indirect incremental value streams of ADSM, peaking generators, 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 the customers' premises, which directly offsets load and avoids both electric transmission costs and line losses. These offsets, avoided costs, and incremental value streams are not always recognized in the IRP process and can be more accurately addressed using the TVM.

[11] Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

A TVM identifies the total value of an ADSM project, by calculating the cost of the project components, then treating avoided costs and offsets as credits. Table 2 lists some of the additional value drivers relevant to an ADSM asset that could be recognized in a TVM. Every utility's situation is unique; and a TVM gives the regulator and the utility the flexibility to adequately assess the full value of an ADSM solution.

Table 2

Value elements for an ADSM project

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 (CO_2e) 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 only during the peak months
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- or geographically-specific basis, targeted load reductions can be used to manage and alleviate transmission congestion or facilitate scheduled or unscheduled facility maintenance.
Outage & 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

V. Five Steps to Regulatory Equivalency for ADSM

There are five key steps that must be considered and addressed in a regulatory model to create regulatory equivalency between ADSM and generation:

- ADSM Asset—Plant in Service
- Operational Costs
- Customer Incentive and Fuel Pass-through
- Total kWh Dispatched
- Avoided Emissions

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.

The costs of operating the ADSM assets are accounted for as operating expenses, just as the costs of operating a generation facility are accounted for. This model for ADSM also includes the equivalent of a fuel adjustment clause, which covers the payments made to customers for participating in demand response and/or allowing the utility to operate their private, behind-the-meter generators.

All of these items above are handled through traditional structures that are already in place. We propose only one minor change from current ratemaking practices: that the utility's costs and recovery should be calculated based on the total generation-equivalent kWh *dispatched* by the utility, whether from traditional generation or from ADSM, rather than on the total kWh sold by the utility to customers. This change recognizes the equivalence of negawatts and megawatts, and together with the recovery method discussed below, avoids the negative impacts of conventional DSM on utility rates and revenues. As with all other aspects of this model, this change makes use of current regulatory structures; however, it will require approval by the regulator because it modifies the regulatory structure, versus incorporating costs into existing structures.

A. ADSM Asset—Plant in Service

The ADSM model gives the utility direct control over the customer's demand by installing control devices on the customer's premises that tie directly into the specific loads to be controlled. For DSM to qualify as ADSM, these control devices must perform as reliably and effectively as a peaking generator performs. They must provide real time communications, real time dispatch and real time verification of signal delivery and resulting load control. The utility must be able to directly dispatch "negawatts" from the customer's premises by curtailing load or by synchronizing behind-the-meter generation to the grid. This allows the ADSM solution to provide system optimization and reliability.

The ADSM control devices and other equipment installed on the customer's premises would be reported as an asset owned and controlled by the utility, and therefore would be includable in rate base consistent with utility accounting standards.[12] This rate base treatment is equivalent to that applied to a new generation asset, and allows the utility to recover its investment and also earn a return, just as if it had constructed a new peaking generation facility.

B. Operational Costs

The costs of operating and dispatching the installed equipment would be treated as an ordinary operating expense.[13] This treatment mirrors the treatment of operational costs associated with generation facilities.

C. Customer Incentive and Fuel Pass-through

The proposed regulatory framework for ADSM also includes an adjustment clause similar to a "fuel adjustment clause."[14] The "fuel" for ADSM service is the payments made to customers that agree to participate in a partnership with the utility and have ADSM equipment installed on their premises, so that energy use can be curtailed when ADSM service is dispatched. Natural gas is the raw material for a gas-fired peaking generation facility, the variable costs of which are modulated by a fuel adjustment clause. Similarly, customer payments are the raw material for ADSM.

Like fuel costs, customer payments comprise a variable cost, in this case dependent on the terms of the specific site agreement, the number of site agreements in place, and how often a particular group of assets are dispatched. As with fuel, 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 most cases, it should be possible to simply modify the utility's existing fuel adjustment clause to include these customer payments.

The customer payments may also include actual fuel costs, if the customer owns a behind-the-meter generation unit that will also be operated during an ADSM event. Customers that allow the utility to dispatch their privately-owned generators will be compensated for their fuel costs, because these costs are attributable to the production of "negawatts" by taking the customer's load off the grid. However, the customers will only be compensated for fuel and operational costs when their assets are dispatched by the utility, and not if they choose to operate their generation unit for other reasons.

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[12] 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 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."

[13] 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.

[14] Operational fuel costs are accounted for under the USoA, in Account 547 "Fuel."

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 between the number of hours the unit was operated by the customer and the number of hours it was dispatched by the utility. So, 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.

Customer payments and fuel costs would be passed through directly into the utility's rates. 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.

D. Total kWh Dispatched

Asset costs, operational costs, customer payments and fuel costs all have direct equivalents to costs that are incurred by traditional generation, and, as discussed, can similarly be included in the utility's revenue requirement. However, a utility recovers its revenue requirement through its rates. Customers are billed based on the kWh that they have consumed, at prices calculated to allow a utility to collect its revenue requirement for an expected volume of sales. However, demand-side options do not lend themselves to this model, because there is no identifiable beneficiary of a negawatt and therefore no customer to bill. Like other demand-side options, ADSM confers benefits that help all customers. For example, ADSM can help integrate more renewables into the system and reduce transmission and distribution upgrade and maintenance costs, lower transmission congestion costs, lower wholesale peak prices, and lower fossil emissions—which benefit all of a utility's customers. In recognition of these broad benefits, we propose a two-fold solution for compensating a utility for negawatts.

1. Rate Calculations

The utility's average rates should be set based on the kWh that the utility is expected to *dispatch* that year ("dkWh"), as opposed to the kWh that it is expected to sell to consumers for consumption. ADSM can be dispatched in the same manner as a generation unit, so it is possible to model and calculate for a given year the expected amount of demand, in kWh, that will be negated by the use of ADSM ("ADSM kWh").[15] dkWH is calculated by adding ADSM kWh to the kWh the utility is expected to sell pursuant to its rate schedules ("kWh sold").

dkWh = kWh sold + ADSM kWh

This change, from kWh sold to dkWh, represents the only substantial change in our framework from traditional ratemaking methodologies. Basing the utility's rates on dkWh treats traditional generation and

[15] As with a generator, if the negawatts fail to materialize when dispatched, there is no payment and penalties could potentially be assessed.

ADSM equally, and makes it is far easier to overcome the throughput incentive and its negative impact on rates and revenues.

Once the dkWh is calculated, the utility's average price per kWh (i.e., its average rate) would then 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 dkWh would be in the denominator, rather than just the kWh sold.

Utility average price per kWh =

$$\frac{\mathbf{RB(ROR) + Opex}}{\mathbf{dkWh}}$$

The use of this formula will prevent the average price per kWh from increasing due to reduced demand, and allow all stakeholder interests to be fully aligned. If necessary, a true up mechanism can account for any variation between actual dispatch and the expected dispatch required for the utility's revenue requirement. However, because this method accounts for ADSM kWh, 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. To receive compensation for providing ADSM, the utility then must determine the value of those ADSM kWh. This value is calculated by multiplying the utility's average price per kWh by the number of ADSM kWh dispatched.

Utility average price per kWh X ADSM kWh = 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 an equivalent number of conventional kWh.

The utility can then recover the value of the ADSM kWh from all of the utility's customers via traditional structures. Costs associated with other services that provide widespread benefits, such as transmission expansion and the administrative costs of regional transmission organizations,[16] are socialized in a similar fashion (whether based on total energy or demand basis). In this case, because ADSM can be dispatched at any time to provide needed capacity balancing on the grid, socializing costs on the basis of demand would be a straightforward and reasonable approach.

E. Avoided Emissions

The proposed regulatory framework for ADSM also includes credit for avoided emissions. A "negawatt" is not presently recognized as a renewable resource, but offsetting generation capacity brings with it the reduction of generation plant emissions. ADSM kWh directly offset the generation capacity requirement

[16] *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).

for the region.[17] 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. We propose that the utilities and regulators track ADSM kWh to calculate emission offset impacts. These will likely have value in utility efforts to comply with environmental mandates. For example, ADSM kWh might be used to attain standards of performance under requirements recently proposed by the U.S. Environmental Protection Agency, which apply to carbon pollution from existing power plants.

VI. Summary: Regulatory Equivalent

The structure described in this white paper allows ADSM assets to be considered in a traditional ratemaking structure in a way that finally encourages utilities to invest in demand-side options. No perfect model exists but we believe without a regulatory model that encourages utilities to consider ADSM to be an option equal to constructing a peaking generation facility, there will be less investment in DSM generally, and ADSM specifically, than is desirable to improve grid operations and maintain utility financial well-being. This model addresses the key cost and recovery components that would allow ADSM recovery in a manner that aligns all stakeholders' goals. Markets or systems that cannot balance supply against flexible demand are inherently more costly and less reliable than systems with multiple supply and demand options. "[R]eliability depends on the relationship among generation, wires, and load."[18] When the relationship is out of balance, decision-makers should look towards load management, as well as towards new investment in generation and wires.[19]

The regulatory modifications proposed here are based on existing regulatory structures, and are fair to the utility and all ratepayers. This framework would allow a utility to include ADSM as a real part of its overall reliability and economic dispatch portfolio and allow the demand side to play a more effective role in improving the economic and operational performance of the electric grid.

[17] However, if behind-the-meter generation is dispatched, those kWh could not be used as offsets.

[18] RICHARD COWART, NAT'L ASS'N OF REGULATORY UTIL. COMM'RS, EFFICIENT RELIABILITY, THE CRITICAL ROLE OF DEMAND-SIDE RESOURCES IN POWER SYSTEMS AND MARKETS 11 (June 2001), at http://www.naruc.org/Publications/EfficientReliability.pdf; *see also id.* at 21-22.

[19] *Id.*

