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August 21, 2015

VIA ELECTRONIC MAIL

Hon. Kathleen H. Burgess
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

RE: Case 14-M-0101 –Comments on Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision

Dear Secretary Burgess:

Advanced Energy Management Alliance hereby submits comments in response to the Notice Inviting Public Comment on Staff White Paper on Benefit-Cost Analysis, dated July 2, 2015, as modified by the Notice Confirming Extension of Deadline for Public Comment on Staff White Paper on Benefit-Cost Analysis, dated August 11, 2015.

Respectfully submitted,

Sincerely,

Katherine Hamilton

Katherine Hamilton
Executive Director, AEMA

Cc: Parties to Case

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEW YORK

Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision

Case 14-M-0101

COMMENTS

From the

ADVANCED ENERGY MANAGEMENT ALLIANCE

Advanced Energy Management Alliance ("AEMA")[1] respectfully submits the following comments in response to the Staff White Paper on Benefit-Cost Analysis ("BCA") in the Reforming Energy Vision ("REV") initiative.

Introduction

AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose

[1] AEMA is an alliance (www.aem-alliance.org) of providers and supporters of demand response united to overcome barriers to nationwide use of demand response for an environmentally preferable and more reliable grid. We advocate for policies that empower and compensate customers to manage their energy usage to make the electric grid more efficient, more reliable, more environmentally friendly, and less expensive.

members include national demand response and advanced energy management service and technology providers, as well as some of the nation's largest demand response resources, who support advanced energy management solutions due to the electricity cost savings those solutions provide to their companies. This filing represents the opinions of AEMA rather than those of individual association members.

Summary

AEMA is pleased that the staff of the Public Service Commission ("Commission") have developed a white paper that lays out a clear framework to identify the many distributed energy resources ("DERs") that are beneficial to the electric grid in the Reforming the Energy Vision ("REV") proceeding (DM 14-M-0101). AEMA would like to point out specific areas of opportunity and potential consideration in measuring the benefits and costs of demand response and advanced energy management solutions. In summary, we suggest that:

- DER performance and output characteristics are too varied and evolve too quickly to be incorporated into BCA handbooks. Instead, the handbooks should set general guidelines for how to value resources, including the appropriate assumptions that should be made about avoided costs.
- Commission should provide clarification on how avoided capacity quantities (*i.e.*, quantity of ICAP megawatts avoided) should be determined for use-limited DERs.

- Expected marginal avoided energy cost calculations should not exclude historical periods of high LBMP. Addressing these anomalous price spikes is one of the large sources of benefit of many DERs.
- The BCA should more fully consider available information on the wholesale price impacts of DER in New York and other ISO markets to see if alternative approaches might better capture this value.
- Participant DER costs—even monetary costs—may prove difficult to quantify. As such, these costs should either receive the same treatment as non-energy benefits—*i.e.*, be treated qualitatively—or more precise methods should be developed for quantifying these costs, including quantifying any directly offsetting participant benefits.
- Finally, BCAs should be conducted taking into account the potential for covariance between relevant variables. Simplified linear models fail to do this and can lead to significant error in valuing DERs.

Specific Comments

The majority of the AEMA comments reference specific sections of the Staff White Paper. Where possible, we have kept the section titles below consistent with Staff's and indicated the page number at which that section appears in Staff's white paper.

BCA Handbook (Handbook) (p. 9)

AEMA appreciates the value of the Handbook, which describes and quantifies the utility's benefit and cost components and their respective application when evaluating DER projects for possible development and agrees, "not all valuation issues are amenable to a generic treatment." This transparent approach to comparing alternative resources and valuing resource types is welcome by the DER community.

AEMA has some concern about what else the Handbook might contain. Staff states "costs of DER alternatives will not be known until the utilities solicit offers from the market in response to particular system needs." However, the white paper adds, "the value of different resources is expected to be explicitly included in the Handbook. Effectively assessing the benefits of DERs requires accurately assessing the amount of energy, capacity and other benefits that those resources can provide, and how often, when and where they will be provided."

AEMA suggests that the Handbook not include assumptions about the characteristics of specific DER resource types—*e.g.*, their output profiles, frequency with which they can be dispatched, or their cost. Making generic assumptions in a Handbook that is only periodically updated ignores the heterogeneity within resource types and the potential for rapid advances in technology. Instead, the Handbook should be limited to defining the appropriate formulas and modeling approaches to value a resource, including appropriate assumptions around utility avoided marginal costs. DER providers who best understand the capabilities of their own resources and technology should provide the particular DER characteristics that are used in completing those models.

Staff also notes in this section that "synergies between resources" should be accounted for in benefit-cost analyses and invites comments on examples of such synergies. AEMA strongly supports this approach and submits the example of demand response resources as a means to better incorporate intermittent renewables at both the grid level and on individual distribution feeders. Demand response can provide stop-gap energy when solar or wind output falters. As the penetration of intermittent resources grows in New York, new markets may need to be established to procure balancing resources ("flexible capacity," as California has termed it) that is capable of responding quickly and repeatedly to variations in supply. Thus the full value of this balancing capability may not be reflected in projections of avoided ancillary service or ICAP purchases as those products are defined today.

Avoided Generation Capacity (ICAP) Costs (p. 13)

Staff suggests a method to determine the marginal cost of avoided capacity (*i.e.*, dollars per megawatt). However, staff does not discuss how it would determine the number of megawatts of capacity that a DER would be credited with avoiding. This has been a contentious issue in cost effectiveness proceedings in other jurisdictions where disagreement has arisen around how the capacity value of a resource that can be deployed only for a limited number of hours per year should be determined.[2] AEMA encourages the Commission to provide clarity on the appropriate approach in these cases from the outset.

Avoided Energy (LBMP) (p. 15)

With regards to the "Avoided Energy (LBMP)" component, AEMA respectfully disagrees with the notion of smoothing out "year-to-year volatility" and eliminating aberrations from pricing histories like the impacts of the "polar vortex." It is especially at times of aberrant market and system conditions when DER provides the most value to the system and to other consumers. While it may be true that measures have been taken to address the oil unavailability which exacerbated the "polar vortex" impacts, there is no guarantee that some other unexpected combination of weather, market and system conditions won't conspire in the future to drive further "aberrant" energy prices. To write off these historic events, we believe, is to significantly undervalue the potential impacts that DER can have in such situations that will inevitably occur at some point. We would recommend an approach to valuing avoided energy costs that draws from a wider sample of historical pricing which includes aberrant values to recognize there is some ongoing probability of these kinds of conditions occurring in the future, and to better reflect the value of DER under such conditions.

[2] California offers one such example. Until recently, they allocated capacity value over the top 250 hours of the year and credited DSM resources only with the capacity value in the hours during which they could run (a penalty referred to as the "A-factor"). Recent proceedings have shown remarkable stakeholder support to move toward a loss-of-load-probability based approach in which statistical simulations are used to determine those hours in the future in which generation shortfall is likely. Capacity value is assigned to hours based on this analysis. (See *Load Modifying Resource Demand Response Valuation Working Group Compliance Report*; May 1, 2015; http://www.clean-coalition.org/site/wp-content/uploads/2015/08/LMR-DR-Valuation-WG-Compliance-Report_FINAL2.pdf, p. 43)

Wholesale Market Price Impacts (p. 19)

With regards to the "Wholesale Market Price Impacts" component, AEMA is concerned that the approaches proposed may undervalue DER, perhaps significantly. There have been a number of studies presented at Independent Service Operator ("ISO") forums which quantify the impacts of DER on wholesale energy and capacity prices in New York and other markets, and which suggest potentially significant and durable cost reductions. One of the primary concepts and drivers for promoting DER in the market is to displace and defer more expensive (and "dirtier") sources of supply. The resulting benefit should naturally be lower ongoing marginal costs that benefit all electric consumers. Of the methods presented, the second is perhaps the best suited, but should have higher percentages for years two and three, though we think the BCA should more fully consider available information on the price impacts of DER to see if alternative approaches might better capture this value[3].

Participant DER Costs (p. 43)

AEMA urges caution when attempting to quantify participant distributed energy resources ("DER") costs for inclusion in a benefit-cost analysis. These costs, especially those that are non-monetary, are difficult to estimate. Elsewhere in its whitepaper, Staff, referring to Net Non-Energy Benefits, suggests, "such difficult-to-quantify costs and benefits not be monetized at this time." We request that staff clarify why the same

[3] Examples include the Consumer Impact Analysis presentation by the NYISO Consumer Interest Liaison at the June 24, 2013 ICAPWG, or the FERC Report to Congress, "Performance Metrics For Independent System Operators and Regional Transmission Organizations" April 2011, page 12.

treatment should not be extended to those participant DER costs that prove difficult to quantify.

Even including seemingly easy-to-quantify monetary costs may not be straightforward. Staff cites the cost of a controllable thermostat as an example of a cost to participate in a bring-your-own-thermostat (BYOT) direct load control (DLC) program. However, virtually no customers purchase smart thermostats solely for the purpose of participating in DLC. Smart, connected thermostats are being sold in record volumes at retail around the country in areas where no BYOT DLC program exists, suggesting that consumers value these thermostats intrinsically and do not see them only as a means to participate in DLC.

The cost of a controllable thermostat (or any other "bring-your-own-device" equipment) should only accurately be called a cost of program participation when a program induces a customer to purchase a thermostat when he or she otherwise would not have. Even in this case, only the difference in the customer's reservation price for purchasing such a device (*i.e.,* his intrinsic valuation of the device) and what was actually paid could rightly be considered a cost. Thus, to suggest that the entire cost of a customer's DER equipment should be counted as a cost of a DER program is likely to be a great exaggeration of actual cost.

Obvious exceptions do exist where the DER equipment cannot be reasonably imagined to have any purpose other than to enable the customer to sell energy or related services.

As Staff acknowledges, comfort and non-monetary opportunity costs are even harder to quantify, which is why AEMA suggests they receive the same treatment as non-energy benefits (*i.e.,* be considered only qualitatively in most cases). It is true that many other jurisdictions have used 75 percent of incentive payments as a proxy for any discomfort or inconvenience that participants might experience when participating in DLC or other DER programs. However, this has never been based on any direct evidence of customer experience. Twenty-five percent might prove an equally reasonable number. If the Commission chooses to use this approach to value non-monetary participant costs, we ask that it attempt to establish a new cost factor from first principles, rather than borrow the 75 percent factor simply because it has been used in the past.

Evidence from many of AEMA members' programs suggests that participants do not typically find DLC events inconvenient or uncomfortable. Customers are often allowed to opt out of a certain number of events per year without penalty, yet few customers ever opt out of that many events. This no-cost, opt-out, opportunity that customers forego suggests that they experience only minimal discomfort, if any.

There are likely many other benefits customers might receive from participating in DER-like programs as the market in New York becomes animated. AEMA cited above the fact that connected thermostats bring a host of intrinsic benefits—increased comfort, control from remote locations, interaction with other smart home devices, etc. Other DER equipment and programs may feature similar benefits—home automation, security, useful data, energy efficiency tips or automation, etc. We ask that, for consistency, if participant costs are quantified, these participant benefits be quantified as well.

Accounting for Covariance or "Option Value"

Finally, throughout the white paper, Staff shows examples of how avoided costs might be calculated by taking the product of a point estimate of expected marginal avoided cost and a point estimate of expected energy or capacity output of a DER (see, *e.g.*, *EXAMPLE: Battery Energy Storage located at a Con Edison Area Substation*, p. 23). AEMA encourages the Commission to avoid using purely linear models based on these types of calculations to value DER. Point forecasts necessarily reflect only one of many possible future states. For example, if a utility handbook suggested that capacity prices would be \$*X*/MW-year three years in the future, it means only that across the many different possible scenarios that might unfold over the next three years, the probability-weighted average resulting price would be \$*X*. Likewise, the projected output of a DER is only a point forecast. Simply taking projected average prices and multiplying by projected average output may appear to produce an accurate estimate of average value; however, in most cases it will not.

If two variables tend to move together they are said to covary. Energy or capacity prices and the output of many DERs, like weather-sensitive demand response loads, often exhibit positive covariance. For example, high temperatures will tend to increase load on the system and drive up energy prices but will also tend to increase the quantity of load that is available to take off the system through demand response. When two variables covary, one cannot achieve an accurate prediction of the product (*e.g.*, price multiplied by quantity, or total DER value) by simply multiplying the best prediction of the first variable by the best prediction of the second variable. Instead, one must adjust for the fact that when price tends to be higher, DER output quantity will tend to be higher as well, and thus expectations of the product should be higher.

Accounting for covariance issues typically requires using probabilistic simulation software more sophisticated than spreadsheets. AEMA appreciates the transparency issues that this may raise, but believes that the benefits of accurately valuing resources will far exceed the cost of that lack of transparency, especially when mitigated by requirements for clear documentation of any probabilistic models used. The correlation between DR output and energy price is just one example of many potential dependencies between variables relevant to valuing DERs. We may not recognize many of the other dependencies until we run proper simulations.

Conclusion

AEMA thanks the Public Service Commission for its leadership on demand response and advanced energy management and for consideration of these comments in further defining a benefit-cost analysis for the Reforming the Energy Vision proceeding.

Should the PSC or staff have any questions regarding this filing, please contact Katherine Hamilton at katherine@38northsolutions.com or 202-524-8832.

Respectfully Submitted,

Katherine Hamilton

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