Cost-Effectiveness of Demand Response

An overview of case studies

June 1, 2018

1200 18th St, NW, Suite 700
Washington, DC 20036
202-524-8832
www.aem-alliance.org

Introduction

The Advanced Energy Management Alliance (AEMA) prepared this summary of Demand Response (DR) cost-effectiveness studies and results from selected utilities and program evaluators as a sample, which is ever-evolving as data are collected. We hope utilities and regulators find this information helpful as they develop DR programs to provide value to customers.

Key results

- C&I demand response programs are *consistently cost-effective*, with cost-benefit ratios far exceeding 1.0 in many programs.
- Incorporating avoided capacity, transmission, distribution, energy, and ancillary service costs into DR programs are accepted best practices to accurately capture the cost-effectiveness of programs. *Program incentives are then a function of these avoided costs* to ensure a cost-effective program.
- There are multiple ways to calculate avoided Transmission and Distribution (T&D) costs. Avoided T&D costs should be specific to a utility's service area and consider how the availability of the program aligns with local peak demand patterns. It is appropriate to use cost estimates in calculations that provide an average value for avoided costs across a territory to provide *meaningful estimates of value without excessive complexity*.
- The DR programs in these studies are *designed with specific purposes in mind,* such as providing capacity for local emergencies or shaving local/retail peaks. They are dispatched with clearly defined event triggers. This ensures that the various value streams (system capacity, local T&D deferrals, etc.) are targeted effectively.

- These programs described below leverage third-party demand response providers to manage and expand customer participation into the program. This helps *drive increased cost-effectiveness* through lower administrative costs and greater customer participation.

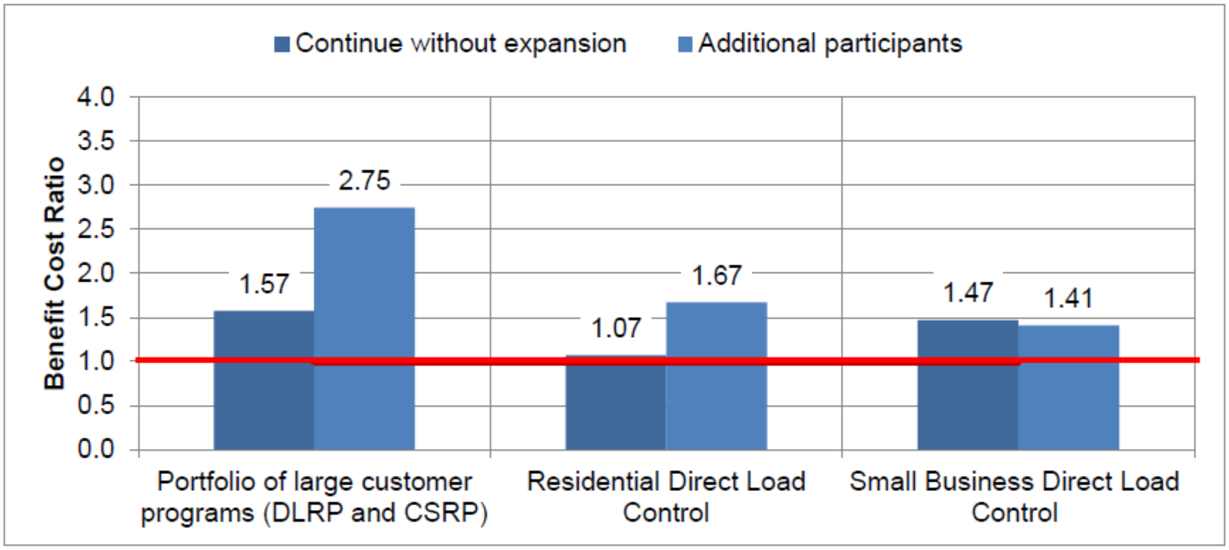
CASE #1: Cost-Effectiveness of CECONY (Con Edison) Demand Response Programs (Nov 2013)[1]

Key findings from this report (summarized on page 72 of the report) include:

- CECONY's DR programs are cost-effective as currently designed, marketed, and operated.
- Adding new participants improves the cost-effectiveness of large customer programs and the residential and small business Direct Load Control (DCL) programs. Benefits from new participants more than offset their variable costs without contributing to a substantial amount of additional overhead.
- The cost-effectiveness results are robust – that is, the programs are cost-effective from multiple perspectives and the results do not change from positive to negative when any of the major inputs are adjusted upward or downward by 20%.
- Cost-effectiveness of the programs can be improved by targeting recruitment efforts at networks where reductions are most valuable and by reducing redundancies associated with dual enrollment.

[1] Josh Bode et al., *Cost-Effective of CECONY Demand Response Programs* (prepared for Consolidated Edison Company of New York) (Freeman, Sullivan & Co. Report, Nov. 2013). Available for download at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBE9E7304-DA3C-4C06-B18B-ADD0D4568E3F%7D

Figure 1-1: Summary of Cost-effectiveness Results[2]



This figure summarizes the cost-effectiveness results for CECONY's large customer and direct load control programs. A further description of the figure is on page 2 of the Executive Summary of the CECONY report.[2]

The CECONY report contains:

- A discussion of fundamental concepts for DR cost-effectiveness – page 11.
- A conceptual illustration of benefits calculation – page 18.
- A table of demand response benefits by cost-effectiveness perspective (e.g., what type of benefits the SCT, UCT, TRC, RIM allow for) – page 19.
- A discussion of avoided T&D capacity costs – page 22.
    - For a detailed discussion of the methodology involved in calculating avoided marginal costs of distribution, see NERA Economic Consulting's 2012 report for CECONY.[3]

[2] *Id*.
[3] *Consolidated Edison Company of New York, Inc. Marginal Cost of Electric Distribution Service* (NERA Economic Consulting, Aug. 23, 2012). Available at

- A discussion of network groups and how DR reductions align with peaking network conditions – page 34.
- The cost-effectiveness analysis for CECONY's C&I programs – page 50.

CASE #2: PA Act 129 Phase III Evaluator Report (Feb 2015)[4]

This report estimates the amount of DR potential for each electric distribution company (EDC) in Pennsylvania and examines the costs and benefits of pursuing statewide policies to encourage DR development and deployment. It finds the large commercial and industrial programs are highly cost-effective for each EDC:

Table 1-10: Day-Ahead MW Potential Net of Current PJM Commitments

EDC	2016 (PY8)	2017 (PY9)	2018 (PY10)	2019 (PY11)	2020 (PY12)	TRC Ratio
Duquesne	281	268	427	426	423	1.94
FE: Met-Ed	-48	-32	266	264	263	1.90
FE: Penelec	-166	-90	262	257	252	1.92
FE: Penn Power	-3	53	123	121	119	1.93
FE: West Penn	120	-10	498	499	499	1.94
PECO	392	448	917	903	889	1.69
PPL	-269	50	731	732	731	1.88
Statewide Potential	**306**	**687**	**3,224**	**3,202**	**3,175**	**1.82**

The table is described on page 11 of the report.

---

https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/REV_BCA_Appendix_B_(Con_Edison_Marginal_Cost_Study_2012).pdf

[4] *Demand Response Potential Pennsylvania* (prepared for Pennsylvania Public Utility Commission) (Statewide Evaluation Team, Final Report, Feb. 25, 2015). Available for download at http://www.puc.pa.gov/pcdocs/1345077.docx

The report also contains a comprehensive review of studies assessing the avoided T&D value of DR programs beginning on page 34. The report examines best practices for estimating avoided T&D costs and then applies a pragmatic methodology within Pennsylvania (also outlined on page 38):

- The first step by the SWE Team (statewide evaluator team hired by the PA PUC) was to gather information on the electric peak load forecast for each EDC.
- Second, the SWE Team requested from each EDC a forecast of annual load-related capital expenditures for new T&D investment for the next five years (2014 to 2018) and ten years (2014 to 2023). For purposes of this DR study, only load-growth related T&D investment (as opposed to customer related) is considered for the development of the forecast of avoidable T&D costs
- Then, for each year from 2014 to 2018, the annual forecast of T&D expenditures for each EDC was divided by the change in the system peak load forecast to arrive at the T&D avoided costs per kW.
- Then, the SWE Team calculated the average T&D avoided costs per kW for the five-year period (2014 to 2018).
- Then, the SWE Team used a capital cost recovery factor to convert the average avoided T&D investment cost for 2014 to 2018 to be on a $ per kW/year basis by applying a capital cost recovery factor. The average value for the 2014 to 2018 time period represents the value used for the starting year of our DR analysis, which was 2016.
- The starting value for the T&D avoided cost per kW/year in 2016 was then escalated at the general rate of inflation for all years after 2016.

This methodology was chosen because it is relatively inexpensive and not as time-consuming relative to other approaches and provides *indicative values* for avoided T&D costs that can be used in cost-effectiveness studies.

It important to note that because of the way Act 129 was implemented in PA, the first round of DR programs in 2012 were not cost-effective.[5] Essentially, peak demand had to be reduced during the top 100 hours, and since the 100 hours were not known ahead of time, customers had to reduce peak for several hours over the 100-hour target, and utilities paid for that reduction. The SWE Team found that targeting the top approximately 25 hours of the summer provided significant benefit at a fraction of the cost of a 100-hour program. The revised program design led to estimates from the SWE Team that the program would result in nearly $1.80 in benefits for every $1.00 spent, with most of the costs taking the form of payments directly to PA businesses, institutions, and local governments. This finding led the PA PUC to create new DR programs for Phase III of Act 129 beginning in 2017.

Table 2-12: T&D Avoided Cost Studies Reviewed by the SWE Team

Title of Study	Date	Firm
Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs[55]	October, 2004	Energy and Environmental Economics
Marginal Transmission & Distribution Cost Estimates[56]	April, 2005	Manitoba Hydro
Avoided Energy Supply Costs in New England[57]	December, 2005	ICF Consulting
Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure[58]	February, 2011	Synapse Energy Economics
Avoided Energy Supply Costs in New England[59]	July, 2011	Synapse Energy Economics
Avoided Energy Supply Costs in New England [60]	July, 2013	Synapse Energy Economics
Maryland Energy - EmPOWER Maryland 2015-2017 Cost-Effectiveness Framework[61]	December 2013	Maryland Energy Administration
PECO T&D Avoided Cost Study[62]	November 2014	Navigant

More information regarding the studies in this table can be found on pages 35-39 of the report.

[5] Pennsylvania Act 129, enacted in 2008, states that "The total cost of any plan required under this section shall not exceed 2% of the electric distribution company's total annual revenue as of December 31, 2006." 66 Pa. C.S. § 2806.1(g).

CASE #3: Update from Program Administrators on Demand Savings Group: Massachusetts (June 2016)[6]

This presentation illustrates how DR cost-effectiveness is assessed in Massachusetts. Avoided cost benefits include energy, capacity, transmission, and distribution value streams, as shown on slide 32. The precedent from this cost-effectiveness approach comes from the Department of Public Utilities order,[7] which outlines the benefits that should be included in cost-effectiveness tests (Appendix on EE Guidelines, pages 9-11). For T&D costs specifically, the guidelines spell out that:

- Avoided transmission benefits are calculated as the product of: (A) an Energy Efficiency Program's capacity savings and (B) an avoided transmission cost factor. The avoided transmission cost factor shall be based on the transmission costs specific to each electric Distribution Company. An Energy Efficiency Plan shall include a detailed description and supporting documentation of the method used to calculate the avoided transmission cost factor.
- Avoided distribution benefits are calculated as the product of: (A) an Energy Efficiency Program's capacity savings and (B) an avoided distribution cost factor. The avoided distribution cost factor shall be based on the distribution costs specific to each electric Distribution Company. An Energy Efficiency Plan shall include a full description of the method used to calculate the avoided distribution cost factor.

---

[6] *Update from PAs on Demand Savings Group* (PowerPoint presentation by "mass save" for the MA EEAC Meeting on June 21, 2016). Available at http://ma-eeac.org/wordpress/wp-content/uploads/Update-from-PAs-on-Demand-Savings-Group.pdf

[7] *Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines*, Massachusetts Department of Public Utilities Case No. 11-120-A, Order Approving Revised Energy Efficiency Guidelines (Jan. 31, 2013). Available for download at http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=11-120%2f13113dpuord.pdf

CASE #4: Orange & Rockland Annual Report on DR Program Performance and Cost Effectiveness (2017)[8]

This is an annual report that Orange & Rockland (O&R) files assessing the performance and cost-effectiveness of its Dynamic Load Management Programs, including its Commercial System Relief Program (CSRP) and its Distribution System Relief Program (DLRP). It finds that the programs are highly cost-effective:

Table 14: 2017 Commercial DLM Portfolio Cost-effectiveness Test Results

Cost Effectiveness Test	SCT	UCT	RIM
Benefits	$17,019,888	$15,078,150	$15,078,150
Costs	$5,791,475	$6,774,649	$6,996,095
Net Benefits	$11,228,413	$8,303,501	$8,082,055
Benefit Cost Ratio	**2.94**	**2.23**	**2.16**

The table from page 16 of the annual report described test results for the Societal Cost Test (SCT), Utility Cost Test (UCT), and Ratepayer Impact Measure (RIM).

The methodology behind the cost-effectiveness evaluation is spelled out in O&R's Benefit Cost Analysis Handbook.[9] It is based on a Standard BCA Handbook template that the NY PSC directed the New York Joint Utilities to develop. The handbook describes general considerations for DR cost-effectiveness testing as well as the detailed methodologies and formulas that O&R uses to assess:

---

[8] *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, New York State Department of Public Service Case No. 14-E-0423, filing of *Orange & Rockland Utilities, Inc. Annual Report on Program Performance and Cost Effectiveness of Dynamic Load Management Programs – 2017* (Dec. 1, 2017). Available for download at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FF056391-946F-4CDA-ACFA-5951FDA7215D}

[9] *In the Matter of Benefit Cost Analysis Handbooks*, New York State Department of Public Service Case No. 16-M-0412, filing of *Orange & Rockland Benefit Cost Analysis Handbook* (June 30, 2016, Rev. Aug. 19, 2016). Available for download at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={063CB6D9-4F76-441B-B1E9-04ACD12E7BF0}

- *Bulk system benefits*, including avoided generation capacity costs, avoided LBMPs, avoided transmission capacity costs and losses, avoided ancillary services, and wholesale market price impacts.
- *Distribution system benefits,* including avoided distribution capacity infrastructure and avoided O&M.
- *Reliability/resiliency benefits,* including net avoided restoration and outage costs.
- *External benefits,* including net avoided CO2, SO2, NOx, and avoided water and land impacts.

CASE #5: MDU (Montana-Dakota Utilities Co.) 2017 Integrated Resource Plan (July 2017)[10]

MDU's IRP contains a demand-side resource analysis that includes an evaluation of the cost-effectiveness of its DSM programs across Montana, North Dakota, and South Dakota. Page 27 contains a summary of the cost-effectiveness results:

Montana-Dakota Utilities Co.
Montana Electric DSM Program Summary

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		2.14	2.56	3.76	6.45	2.59
Residential Programs						
Residential Lighting	Residential	1.05	3.13	2.63	2.57	1.61
Demand Response						
Residential AC Cycling	Residential	1.38	1.41	3.03	3.47	1.99
Commercial Programs						
Commerical Lighting	Commerical	1.50	6.33	7.12	4.13	3.76
Commercial Partnership Program (Custom)	Commerical	1.40	6.14	5.28	3.48	3.15
Demand Response						
Commercial Demand Response Program	Commercial	2.58	2.58	3.53	40.52	2.54
Interruptible Rate DR Program	Commercial	3.44	3.53	4.47	10.81	3.22

[10] *Montana-Dakota Utilities Co. 2017 Integrated Resource Plan*, submitted to the North Dakota Public Service Commission, July 1, 2017, Volume I. Available at https://www.montana-dakota.com/docs/default-source/rates-and-services/rates-tariffs/2017-nd-irp---volume-1---non-print.pdf?sfvrsn=2

MDU contracts with a Demand Response provider to recruit and manage customer interface between the utility and the customer. The C&I DR programs are highly cost-effective with total resource costs (TRC) of 2.54 and 3.22, respectively. The rest of the page contains additional cost-effectiveness results for the North Dakota and South Dakota C&I DR programs—all of which have TRC ratios of 1.69 or greater. Additional detail outlining the methodologies behind the cost-effectiveness tests can be found in Attachment B of MDU's 2015 IRP report.[11]

About Advanced Energy Management Alliance

AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including DR providers, as well as some of the nation's largest demand response and distributed energy resources.[12] Over the course of the last year, AEMA has initiated discussions with key stakeholders throughout MISO to understand how DR currently participates in MISO states, and how we can collaborate to enhance the benefits of DR. This report is an effort of a group of AEMA members and represents the collective consensus of AEMA as an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies.

Acknowledgements

AEMA is grateful to its members for contributing to this report, including Monica Berry of NRG, Bruce Campbell and Peter Dotson-Westphalen of CPower, Greg Geller and Nicholas Papanastassiou of EnerNOC, Frank Lacey of Electric Advisors Consulting, as well as our consultants, Phyllis Reha and Ingrid Bjorklund of PAR Consulting. Katherine Hamilton serves as Executive Director of AEMA.

[11] *Montana-Dakota Utilities Co. 2015 Integrated Resource Plan*, submitted to the North Dakota Public Service Commission, July 1, 2015, Volume III: Attachment B. Available at https://www.montana-dakota.com/docs/default-source/2013-irp/2015-mdu-irp-report---volume-iii.pdf

[12] For more information, visit AEMA's website: http://aem-alliance.org