Before the
Commonwealth of Virginia State Corporation Commission

DIRECT TESTIMONY OF
TIM WOOLF
AND
ERIN MALONE

ON BEHALF OF
THE SIERRA CLUB

BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA

Application of Virginia

Electric and Power Company for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia.

Case No. PUR-2018-00168

PUBLIC VERSION

February 6, 2019

Summary of the Direct Testimony of Tim Woolf and Erin Malone.

Our testimony includes the following conclusions regarding the proposed DSM program budgets and additional DSM opportunities of the Virginia Electric and Power Company (the Company):

1. The DSM Programs, which are based on those filed by the Company in its 2018 IRP, do not meet Senate Bill 966, the Grid Transportation and Security Act (GTSA), which requires the Company to propose DSM budgets of $870 million over the next ten years.
2. The Company's 2018 IRP and proposed DSM Programs do not represent the full opportunity for cost-effective DSM available to the Company since the IRP did not investigate the full potential for cost-effective DSM Programs.
3. The Company's proposed DSM Programs are cost-effective according to the Company's application of the Utility Cost test, the Total Resource Cost (TRC) test, and the Participant test.
4. The Utility Cost Test, TRC Test, and Participant Test, as applied by the Company, do not include some important utility system benefits, participant non-energy benefits and other fuel impacts; thereby underestimating the actual benefits.
5. While the Company should include an analysis of the Ratepayer Impact Measure (RIM) test in its cost-effectiveness evaluation, the RIM test should be given little weight since, for example, it conflates cost-effectiveness with cost-shifting. Long-term rate, bill, and participant analyses offer a much better way to analyze rate impacts than the RIM test.
6. The Company's recent DSM Potential Study indicates that a ten-year DSM scenario with budgets similar to the GTSA $870 million budget mandate would result in a *net reduction* in electricity costs of $1,286 million, in cumulative present value terms.
7. The Company could significantly increase DSM program savings and customer participation through better program design.
8. The energy savings from the Company's proposed DSM Programs and their corresponding budgets are expected to be small relative to other utilities in the region and the US.

Our testimony includes the following recommendations regarding the proposed DSM program budgets and additional DSM opportunities:

1. Approve the proposed DSM Programs because they are cost-effective and in the public interest.
2. Direct the Company to file corrected DSM Programs complying with the GTSA mandate of proposing budgets of no less than $870 million in DSM programs.
3. Direct the Company to provide annual budgets and clarify that the annual DSM budgets should achieve the cumulative ten-year budget mandate and ensure a consistent, predictable, and practical approach to compliance with the GTSA mandate.
4. Clarify that the GTSA budget mandates represent a *minimum* budget to be proposed.
5. Clarify that budgets used for compliance with the GTSA mandates should not include lost revenues from DSM programs.
6. Direct the Company to apply the Utility Cost, the TRC, and the Participant tests consistent with their theoretical definitions and to include all relevant impacts, as described in our testimony.
7. The Company should conduct a long-term rate, bill, and participant impact analysis as part of its cost-effectiveness analyses. This analysis should be used in addition to the RIM test to investigate the potential rate impacts of DSM programs.
8. Direct the Company to investigate additional DSM opportunities in the corrected DSM Programs and all future DSM Program filings with input and review of the stakeholder process required by the GTSA. The additional opportunities should be consistent with (a) GTSA budget mandates; (b) the Company's DSM potential studies; (c) best practices in DSM program design; and (d) savings and budgets consistent with other utilities in the region and the US.

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. **Mr. Woolf:** My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. **Ms. Malone:** My name is Erin Malone. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. **Mr. Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Commission, including several electric and gas utility rate cases.

A large portion of my career has been dedicated to the review and development of energy efficiency programs and regulatory policies. My work encompasses all aspects of energy efficiency program planning and implementation, including program design, avoided cost analyses, cost-benefit analyses, cost recovery, decoupling, utility performance incentives, integrated resource planning, and other relevant regulatory policies.

I have reviewed and critiqued utility energy efficiency programs and policies in twenty states and Canadian provinces—including Arkansas, British Columbia, Colorado, Delaware, Florida, Georgia, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Missouri, Nevada, New Brunswick, New York, Nova Scotia, Prince Edward Island, Rhode Island, Québec, and Vermont—and have also led several national and regional studies addressing energy efficiency program opportunities and policy issues. I am the lead technical advisor for the National Efficiency Screening Project and was the primary author of the National Standard Practice Manual for Assessing the Cost-Effectiveness of Energy Efficiency Resources.

I have testified as an expert witness in more than 45 state regulatory proceedings and have authored more than 60 reports on electricity industry regulation and restructuring. I represent clients in collaboratives, task forces, and settlement negotiations, and have published articles on electric utility regulation in Energy Policy, Public Utilities Fortnightly, The Electricity Journal, Local Environment, Utilities Policy, Energy and Environment, and The Review of European Community and Environmental Law.

I hold a Master's in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume is attached as Exhibit TW/EM-1.

A. **Ms. Malone:** I have approximately seven years of experience in research and consulting at Synapse, focused almost entirely on energy efficiency policy. While at Synapse, I have focused on energy efficiency cost-effectiveness, rate and bill impacts, participation analysis, and best practices for energy efficiency. Prior to joining Synapse, I served as an economist in the Electric Power Division at the Massachusetts Department of Public Utilities from June 2008 through December 2011, specializing in the review of electric utilities' energy efficiency activities. I have a bachelor's degree in economics from Boston College, and I am accredited as a LEED Green Associate. My resume, attached as Exhibit TW/EM-2, presents additional details of my professional and educational experience.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Sierra Club.

Q. Have you previously testified before a state commission?

A. **Mr. Woolf:** Yes. I have testified as an expert witness in more than 45 state and provincial regulatory proceedings. Many of those testimonies were related to energy efficiency resources and integrated resource planning, while in recent years I have increased attention on issues related to grid modernization and distributed energy resources.

Ms. Malone: Yes. I have testified before the Massachusetts Department of Public Utilities on six separate occasions since 2014. All instances were related to energy efficiency filings.

Q. Have you previously testified before the State Corporation Commission of Virginia?

A. **Mr. Woolf:** No.

Ms. Malone: No.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review and critique the DSM Programs proposed by the Virginia Electric and Power Company (the Company). Our testimony focuses on how well the proposed DSM Programs comply with statutory and regulatory requirements, the proposed DSM program spending and savings levels, DSM program design, and DSM cost-effectiveness.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. we are sponsoring the following exhibits:

EXHIBIT NO.	CONTAINS EXTRAORDINARILY SENSITIVE INFORMATION	CONTAINS
TW/EM-1	No	Resume of Tim Woolf
TW/EM-2	No	Resume of Erin Malone
TW/EM-3	Yes	Response to Staff Set 1-02 with Extraordinarily Sensitive Attachment Staff Set 1-02 (JEB)

TW/EM-4	No	Response to Sierra Club 3-1
TW/EM-5	Yes	Response to Sierra Club 4-13 with Extraordinarily Sensitive Attachment 4-13
TW/EM-6	No	Response to Sierra Club 2-6
TW/EM-7	No	Response to Sierra Club 2-14
TW/EM-8	No	Response to Sierra Club 2-15
TW/EM-9	No	Response to Sierra Club 3-2
TW/EM-10	No	Response to Sierra Club 3-3
TW/EM-11	No	Response to Sierra Club 3-4
TW/EM-12	No	Response to Sierra Club 3-5
TW/EM-13	No	Response to Sierra Club 2-5
TW/EM-14	No	Response to Sierra Club 4-3
TW/EM-15	No	Response to Sierra Club 5-1
TW/EM-16	No	National Efficiency Screening Project, the National Standard Practice Manual for Assessing the Cost-Effectiveness of Energy Efficiency Resources (Spring 2017)
TW/EM-17	No	Response to Sierra Club 2-11
TW/EM-18	No	Response to Sierra Club 5-9
TW/EM-19	No	Response to Sierra Club 2-12
TW/EM-20	No	Response to Sierra Club 2-13
TW/EM-21	No	Response to Sierra Club 2-4, Attachment 2-4(DRK)(3) – DNV-GL Dominion Energy Efficiency Potential Study: 2018-2027 (Oct. 17, 2017)
TW/EM-22	No	Response to Sierra Club 5-5

TW/EM-23	No	Response to Sierra Club 3-20
TW/EM-24	No	Response to Sierra Club 4-9
TW/EM-25	No	Response to Sierra Club 4-10
TW/EM-26	No	Selections from ACEEE, The New Leaders of the Pack: ACEEE Fourth National Review of Exemplary Energy Efficiency Programs, Report U1901 (Jan. 2019)
TW/EM-27	No	AEEE Energy Efficiency Resource Standards
TW/EM-28	No	Response to Sierra Club 3-16
TW/EM-29	No	Response to Sierra Club 3-14
TW/EM-30	No	Response to Sierra Club 3-15
TW/EM-31	No	Response to Sierra Club 4-6
TW/EM-32	No	EIA 861 Data Website
TW/EM-33	No	Selections from ACEEE Scorecards from 2013-2018, Savings as Percent of Sales
TW/EM-34	No	Selections from ACEEE Scorecards from 2013-2018, Spending as Percent of Revenue
TW/EM-35	No	Response to Sierra Club 4-8

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

2.1. Summary of Conclusions

Q. Please summarize your conclusions regarding the proposed DSM program budgets.

A. Our conclusions regarding the proposed DSM program budgets are summarized as follows:

- The DSM Programs do not meet the provision of Senate Bill 966, the Grid Transportation and Security Act (GTSA), requiring the Company to propose DSM budgets of $870 million over the next ten years.
- The DSM Programs are based on those filed by the Company in its 2018 IRP, which was rejected by the Commission for several reasons, including the fact that the Company did not properly analyze the DSM budget mandate in the GTSA.
- The Company's cumulative budgets for six years is $705 million *less* than the cumulative GTSA budgets for ten years. If the Company were to attempt to make up this shortfall in the remaining four years of the time period, it would need to expand its budgets (and commensurate program activities) by roughly a factor of five relative to the Phase VII budgets. This would be an extremely impractical and inefficient way to comply with the GTSA budget mandate.
- A more practical, consistent, and predictable budgeting approach would require annual budgets of roughly $93 million. Instead, the Company is proposing to spend on average roughly $24 million per year over the next five years; which is only 26% of the more practical approach.
- The Company has not been forthcoming or transparent regarding its progress toward the GTSA energy efficiency budget mandate and has significantly overstated what little progress it has made by including lost revenues as a budgetary item.

Q. Please summarize your conclusions regarding the cost-effectiveness of the proposed DSM programs.

A. Our conclusions regarding the cost-effectiveness of the proposed DSM programs are summarized as follows.

- The Company's proposed DSM Programs are cost-effective according to the Company's application of the Utility Cost test, the Total Resource Cost (TRC) test, and the Participant test. Therefore, the Company's proposed DSM Programs meet the requirement of being cost-effective according to three of the four traditional cost-effectiveness tests.

- The Utility Cost test is the most useful test for determining which DSM programs are cost-effective. According to the Company's application of the Utility Cost test, the Company's proposed DSM programs are very cost-effective:
    - The benefit-cost ratio (BCR) of the portfolio of programs is estimated by the Company to be 3.7, which means that every utility dollar spent on energy efficiency programs is expected to result in $3.70 reduced utility costs.
    - The present value of net benefits from the portfolio of programs is estimated by the Company to be $706 million.
- The Utility Cost test as applied by the Company does not include some important utility system benefits of energy efficiency programs, including: wholesale market price suppression effects, avoided costs of complying with renewable portfolio standards, avoided environmental compliance costs, avoided credit and collection costs, reduced risk, and increased reliability.
- The TRC test as applied by the Company does not include some important participant benefits, including: participant non-energy benefits and other fuel impacts. The TRC test as applied by the Company also does not include those utility system benefits that are missing from the Utility Cost test, as noted above.
- The Participant test as applied by the Company does not include some important participant benefits, including: participant non-energy benefits and other fuel impacts.
- The Ratepayer Impact Measure (RIM) test does not provide useful information, is inconsistent with economic theory, is inconsistent with fundamental principles of the National Standard Practice Manual (NSPM), is misleading, and conflates cost-effectiveness with cost-shifting. Long-term rate, bill, and participant (RBP) analyses offer a much better way to analyze rate impacts than the RIM test. While the Company should include an analysis of the RIM test in its cost-effectiveness

evaluation, it should give little weight to the RIM test to determine whether DSM programs are cost-effective.

- The Company's 2018 IRP was used as the basis for the cost-effectiveness analysis supporting the Company's proposed DSM Programs. However, the 2018 IRP did not investigate the full potential for cost-effective DSM programs, because it used a single set of DSM resources in every scenario and therefore did not explore how much additional cost-effective DSM exists. Therefore, the Company's 2018 IRP and proposed DSM Programs do not represent the full opportunity for cost-effective DSM available to the Company.

Q. Please summarize your conclusions regarding additional opportunities for DSM savings.

A. We find that there are significant opportunities for achieving cost-effective DSM savings beyond what is included in the proposed DSM Programs.

- The Company's recent DSM Potential Study indicates that there are significantly greater cost-effective efficiency savings available to the Company. If the Company's DSM Program savings were compared to the DSM Potential Study savings over a comparable time period, the savings in the Company's DSM Programs would be only 46% of the cost-effective efficiency opportunities identified in the DSM Potential Study.

- The DSM Potential Study finds that a ten-year DSM scenario with budgets similar to the GTSA $870 million budget mandate would result in a *net reduction* in electricity costs of $1,286 million, in cumulative present value terms. By not proposing a set of DSM programs to meet the GTSA budget mandate, the Company is forgoing the opportunity to achieve these savings, thereby unnecessarily increasing electricity costs.

- The Company could significantly increase DSM program savings and customer participation through better program design. Modifications such as serving all market segments, serving all customer types, and addressing all end-uses would significantly increase the savings and net benefits to customers.

- The energy savings from the Company's proposed DSM Programs are expected to be small relative to other utilities across the US. The Company is expected to save roughly 0.13 percent of sales each year through DSM programs, while the national average is roughly 0.75 percent of sales, and many utilities are achieving 1.0 percent, 2.0 percent and higher.
- The budgets of the proposed DSM Programs are also small relative to other utilities across the US. The Company plans to spend roughly 0.4 percent of its revenues on DSM programs, which is well below the national average and well below several utilities in the region. If the Company were to propose DSM budgets that were consistent with the GTSA budget mandates, then that would equal roughly 1.0 percent of revenues, which is consistent with the US average spending levels.

2.2. Summary of Recommendations

Q. Do you recommend the commission approve the Company's proposed DSM Programs?

A. Yes. The proposed DSM Programs are clearly cost-effective and in the public interest, and the Company should be allowed to proceed with them immediately. However, we also recommend the Commission direct the Company to file corrected DSM Programs to address the issues raised in our testimony. The corrected DSM Programs should be prepared with input and review from the stakeholder process required by the GTSA.

Q. Please summarize your recommendations regarding the proposed DSM program budgets.

A. We recommend that the Commission direct the Company to file corrected DSM Programs complying with the GTSA mandate of proposing a portfolio of DSM programs with budgets no less than $870 million.

Further, we recommend that the Commission make several important clarifications regarding the DSM Program budgets. These clarifications should apply to the corrected DSM Programs and all future DSM proceedings.

- Direct the Company to provide more transparent and complete documentation of annual DSM program budgets, including all the phases of DSM programs and all the components of the DSM budgets, such as O&M costs, common costs, margin, evaluation, or any other costs.
- Direct the Company to provide annual budgets and clarify that the annual DSM budgets should be large enough to achieve the cumulative ten-year budget mandate and ensure a consistent, predictable, and practical approach to compliance with the GTSA mandate.
- Clarify that the GTSA budget mandates represent a *minimum* budget to be proposed for DSM programs that are reviewed and approved by the Commission.
- Clarify that budgets used for compliance with the GTSA mandates should not include lost revenues from DSM programs.

Q. Please summarize your recommendations regarding the cost-effectiveness of the proposed DSM programs.

A. We recommend the Commission make several important clarifications regarding the cost-effectiveness analyses of energy efficiency programs. These clarifications should apply to the corrected DSM Programs and all future DSM proceedings.

- The Company should continue to use the Utility Cost, the TRC, and the Participant tests to evaluate DSM cost-effectiveness. However, these tests as applied by the Company should be improved and updated to be consistent with their theoretical definitions and to include all relevant impacts, as described below.
- In applying the Utility Cost test, the Company should include all utility system impacts that are expected to have a material impact on the results. This means adding the following utility system benefits to the test that is currently used by the Company: avoided costs of compliance with environmental regulations; wholesale market price suppression effects; reduced risk; and increased reliability. (If the full amount of utility system impacts is not included in the Utility Cost test, then at a minimum the Commission should recognize the test will undervalue the benefits of energy efficiency.)
- In applying the TRC test, the Company should include all utility system impacts that are expected to have a material impact on the results, in the same way that they are included for the Utility Cost test. (If the full amount of utility system impacts is not included in the TRC test, then at a minimum the Commission should recognize that the test will undervalue the benefits of energy efficiency.)
- In applying the TRC test, the Company should include all relevant participant impacts, including other fuel impacts and non-energy impacts. (If all relevant participant impacts are not included in the TRC test, then at a minimum the Commission should recognize that the TRC test will significantly undervalue the benefits of energy efficiency.)
- The avoided cost of compliance with environmental regulations should reflect the most likely scenario for carbon reduction requirements, including the most likely scenario for Virginia joining RGGI. Any assessment of the costs and benefits of compliance with any environmental regulations should assess the full range of energy efficiency opportunities available to determine the optimal level of efficiency resources that can be used to minimize the costs of compliance.

- The Company should give little weight to the RIM test in its cost-effectiveness evaluation, either in isolation or by adding its results to the results of the other tests. Instead, the Company should ensure that its DSM programs pass the other three cost-effectiveness tests.
- The Company should conduct a long-term rate, bill, and participant impact analysis as a part of its cost-effectiveness analyses. This analysis should be used in addition to the RIM test to investigate the potential rate impacts of DSM programs.
- The Company should assess the cost-effectiveness of several different amounts of energy efficiency budgets and savings, including budgets consistent with the GTSA mandates, to identify the optimal level of energy efficiency resources available.

Q. Please summarize your recommendations regarding additional DSM opportunities.

A. We recommend the Commission direct the Company to investigate additional DSM opportunities in the corrected DSM Programs and all future DSM Program filings. These additional opportunities should be investigated with input and review of the stakeholder process required by the GTSA. The additional opportunities should be consistent with (a) GTSA budget mandates; (b) the Company's DSM potential studies; (c) best practices in DSM program design; and (d) savings and budgets consistent with other utilities in the region and the US.

3. SUMMARY OF THE COMPANY'S DSM PROGRAMS

Q. Please provide an overview of the DSM Programs the Company is proposing the Commission approve in the current proceeding.

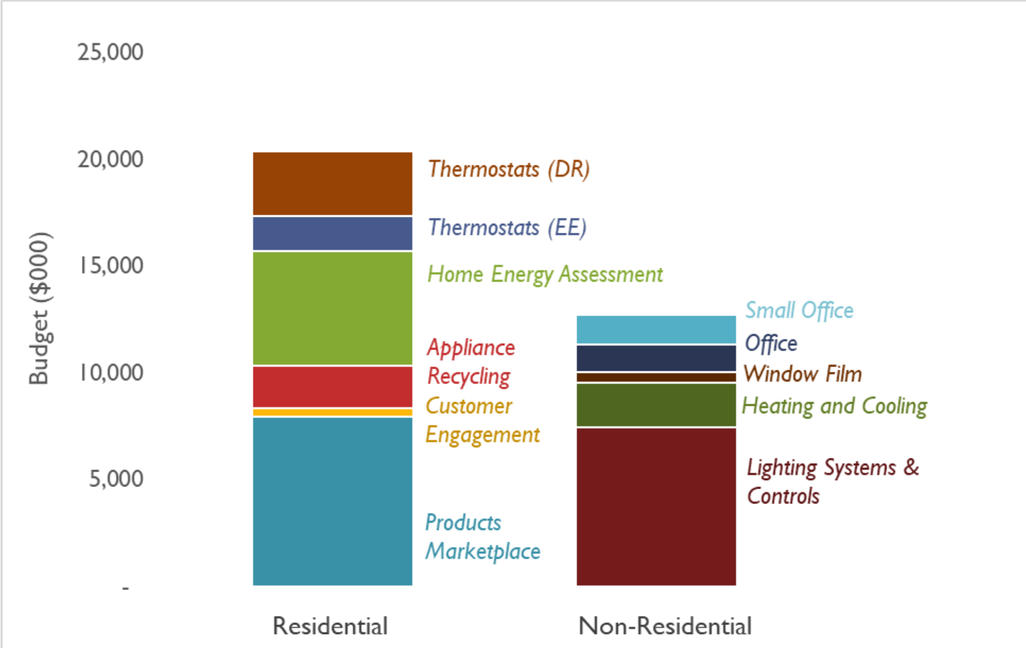
A. For Phase VII, the Company proposes to implement eleven new DSM programs over the five-year period of 2019 through 2023. The eleven proposed programs are: (1) Non-residential Heating and Cooling Efficiency; (2) Non-residential Lighting Systems & Controls; (3) Non-residential Window Film; (4) Non-residential Office; (5) Non-residential Small Manufacturing; (6) Residential Appliance Recycling; (7) Residential Home Energy Assessment; (8) Residential Smart Thermostat Management (DR); (9) Residential Smart Thermostat Management (EE); (10) Residential Efficient Products Marketplace; and (11) Residential Customer Engagement.[1]

Q. Please summarize the DSM Program budgets proposed by the Company.

A. Figure 1 presents the program budgets for 2021, the year with the highest proposed DSM budget. The Company proposes to spend about $20 million on residential programs and about $13 million on non-residential programs, or 62 percent and 38 percent of the budget, respectively.

[1] Application for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia at 7-8.

Figure 1. 2021 Budget by Program

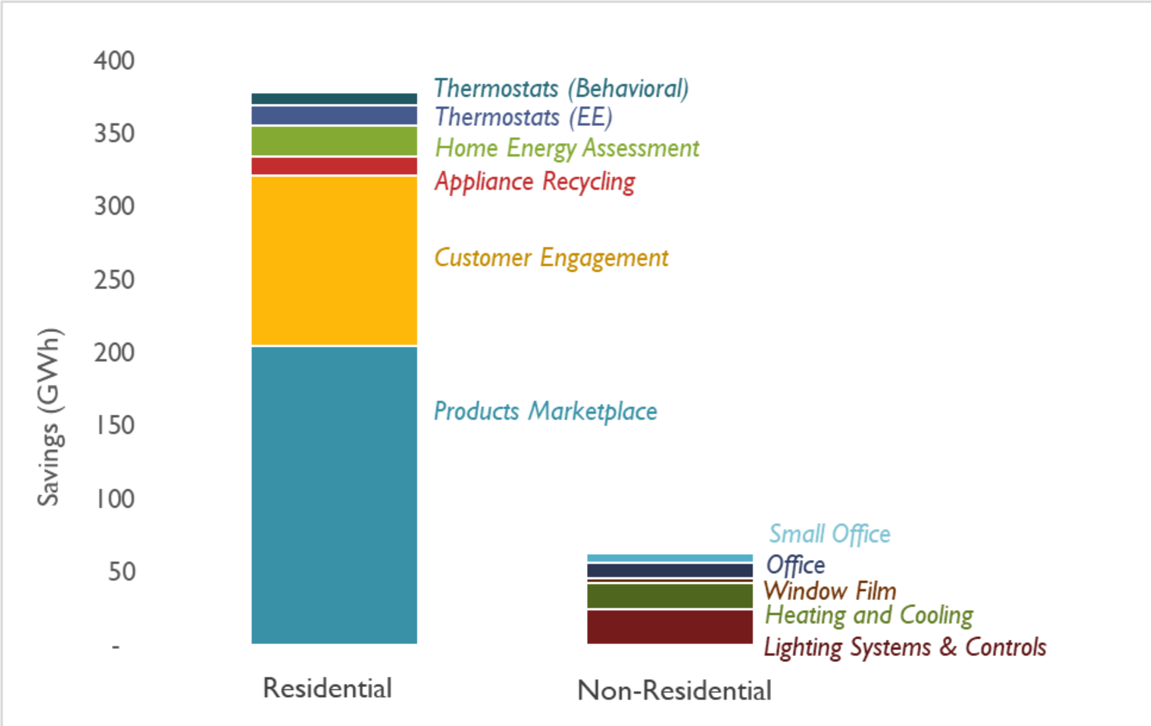


Source: Direct Testimony of Deanna Kesler, Schedule 8.

Q. Please summarize the energy savings expected from the proposed DSM Programs.

A. The energy savings are presented in Figure 2 for 2021. As indicated, residential program savings are significantly higher than the non-residential program savings. Among the residential programs, the Residential Products Marketplace and Residential Customer Engagement programs have the greatest amount of savings, representing 54 percent and 31 percent of residential program savings, and 46 percent and 26 percent of total program savings, respectively.

Figure 2. 2021 System-Level Energy Savings



Source: Direct Testimony of Deanna Kesler, Schedule 7.

Q. Are the proposed DSM Programs cost-effective?

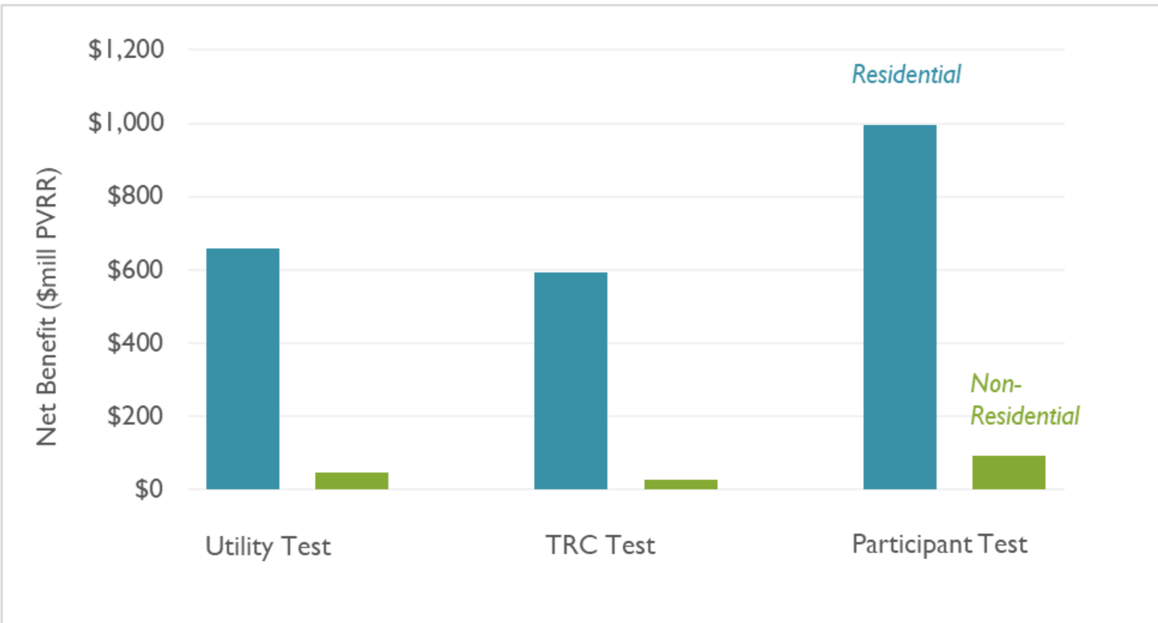
A. Yes, according to the Company's analysis they are cost-effective. Figure 3 presents the benefit-cost ratios for the Utility Cost Test, Total Resource Cost Test, and Participant Test for the residential programs, non-residential programs, and the total portfolio of programs. As indicated, all the sectors have a benefit-cost ratio greater than one, and some much greater than one. The portfolio of programs has a BCR of 3.7 for the Utility Cost Test, a BCR of 2.8 for the Total Resource Cost Test, and a BCR of 6.0 for the Participant Cost Test.

Figure 4 presents the net benefits, in terms of cumulative present value of revenue requirements, for the Utility Cost Test, Total Resource Cost Test, and Participant Cost Test for the residential programs and non-residential programs. The portfolio of programs provides net benefits of $706 million for the Utility Cost Test, $618 million for the Total Resource Cost Test, and $1,085 million for the Participant Cost Test.

Figure 3. Benefit-Cost Ratios by Cost-effectiveness Test

Source: Direct Testimony of Deanna Kesler, Schedule 2.

Figure 4. Net Benefits by Cost-effectiveness Test



Source: Direct Testimony of Deanna Kesler, Schedule 2.

4. DSM PROGRAM BUDGETS

4.1. The GTSA Budget Mandate

Q. Please describe the GTSA budget mandate.

A. The GTSA requires the Company to propose DSM programs with budgets that are no less than $870 million for the program years 2018/19 through 2028/29. The relevant language is quoted below.

> That each Phase I Utility and Phase II Utility, as such terms are defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall develop a proposed program of energy conservation measures. Any program shall provide for the submission of a petition or petitions for approval to design, implement, and operate energy efficiency programs pursuant to subdivision A 5 c of § 56-585.1 of the Code of Virginia. At least five percent of such energy efficiency programs shall benefit low-income, elderly, and disabled individuals. *The projected costs for the utility to design, implement, and operate such energy efficiency programs, including a margin to be recovered on operating expenses, shall be no less than an aggregate amount* of $140 million for a Phase I Utility and *$870 million for a Phase II Utility* for the period beginning July 1, 2018, and ending July 1, 2028, including any existing approved energy efficiency programs.[2]

Q. Do you have any concerns about how the Company is characterizing its program budgets in the context of the GTSA budget mandate?

A. Yes. First, the Company has provided very little information on how its DSM budgets compare with the GTSA budget mandates. Given the importance of this statutory requirement, the Company should have compared its proposed budgets to the GTSA

[2] Senate Bill 966, 2018 Virginia General Assembly ¶ 15 (March 1, 2018) (emphasis added).

budget mandates in its initial filing, in a prominent location. Instead, we had to ask several rounds of discovery to obtain this data, and the Company did not clearly answer these important questions.[3] More importantly, some of the budget information that the Company did provide is inaccurate.

Q. Please explain why some of the budget information submitted by the Company in this docket is inaccurate.

A. In his direct testimony, Mr. Bates discusses the progress that the Company is making toward the GTSA budget requirement. He states the Company has proposed approximately $262 million in energy efficiency programs. This includes approximately $26 million for program year 2018 and $20 million for program year 2019 for active programs from Phases I-VI, and $215 million for the five years of DSM Phase VII programs proposed in this docket.[4] In a footnote, Mr. Bates adds that the $215 million includes "estimates for program costs, common costs, margin, and lost revenue."[5] Our review of Mr. Bates' detailed budget tables confirms the Company is including lost revenues in these Phase IV budget values.[6]

Lost revenues from energy efficiency programs are not a budgetary item and should not be included in the DSM budgets in this way. To do so is clearly inaccurate.

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[3] *See* Company's responses to Sierra Club 2-5, 3-1, 3-5 and 4-3, attached as Exhibits 13, 4, 12 and 14 respectively.

[4] *See* Direct Testimony of Jarvis Bates at 9, lines 7-14.

[5] *See* Direct Testimony of Jarvis Bates at 9, footnote 3.

[6] *See* Attachment Staff Set 1-02 (JEB) (Extraordinarily Sensitive) and Attachment Sierra Club 4-13 (Extraordinarily Sensitive), attached as Exhibits 3 and 5 respectively.

Q. Please explain why lost revenues should not be included as part of the DSM budgets.

A. Lost revenues are not a new cost created by energy efficiency programs, as implied by the Company's approach of including it in the budget estimate. Lost revenues are the revenues that the utility would have recovered from customers if not for the reduced sales from energy efficiency programs. Thus, lost revenues are not a cost at all; they are a reduction in revenues. Customers are affected by lost revenues when a utility needs to increase rates in order to pay for existing costs that would have otherwise been covered through the revenues that were lost. Thus, the costs that drive the need to increase rates to recover lost revenues are not new costs associated with energy efficiency programs. Instead, they are costs that have already been incurred by the Company and are already embedded in base rates before the DSM programs are even implemented. They are fixed, sunk costs associated with generation, transmission, and distribution facilities that are included in rates and need to be recovered from customers. To include these costs as part of the energy efficiency budgets is clearly incorrect.

Further, we have reviewed energy efficiency plans and budgets across many states and provinces for over 30 years and have never seen another utility categorize lost revenues as a part of the program budgets. Many states have discussed how to treat lost revenues, and how to recover them through decoupling, performance-based regulation, or lost revenue adjustment mechanisms, but none of them to our knowledge consider lost revenues to be a DSM program cost or budgetary item.

4.2. The Company's Proposed DSM Budgets

Q. Do the Company's proposed DSM Programs comply with the DSM GTSA budget mandate?

A. No. The proposed DSM Programs budgets are not even close to the GTSA budget mandates. Table 1 provides a summary of the Company's proposed DSM budgets, including the budgets for Phases I through VI programs that are still active,[7] and the budgets proposed for Phase VII. For the Phase VII budgets, we present lost revenues separately from the other program costs, because lost revenues should not be included as part of DSM budgets.[8]

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[7] The budgets for Phases I-VI programs are based on the data provided in Exhibit 5 (Extraordinarily Sensitive). We note that in the Direct Testimony of Michael Hubbard at 3-8 and Schedule 3, the Phase I-VI programs appear to have different budgets and are implemented for longer periods of time than what is shown in Exhibit 5 (Extraordinarily Sensitive). For example, Exhibit 5 (Extraordinarily Sensitive) does not include budgets from programs that are listed as still active for Phases I and II. Further, the Company does not appear to include costs associated with the Residential Smart Thermostat DR Program towards the $870 million budget mandate. Finally, the Company does not make clear in the Direct Testimony of Michael Hubbard, Schedule 3 which costs were included in the budget numbers (e.g., lost revenue, margin, program costs, and/or common costs).

[8] From Exhibit 3 (Extraordinarily Sensitive) we summed annual program costs, margin, and lost revenue. For common costs, we used the program-specific, five-year common costs from Exhibit 5 (Extraordinarily Sensitive) and allocated them to each year by each program's percent of annual program cost spending.

Table 1. Proposed DSM Budgets and Lost Revenues ($1000)

Year	Active Programs (Phases I-VI)	Proposed Programs (Phase VII)			Total
		Program, Common, and Margin	Lost Revenue	Total	
2018	25,860			-	25,860
2019	20,425	18,196	2,314	20,511	40,935
2020	-	23,929	8,057	31,987	31,987
2021	-	24,588	17,955	42,543	42,543
2022	-	25,406	28,593	53,998	53,998
2023	-	26,289	39,968	66,257	66,257
2024	-			-	-
2025	-			-	-
2026	-			-	-
2027	-			-	-
Total	**46,285**	**118,408**	**96,887**	**215,295**	**261,580**

Source: Exhibit 3, Schedule 7 (Extraordinarily Sensitive) and Exhibit 5 (Extraordinarily Sensitive). The Company includes $0 for lost revenues for active programs.[9]

As indicated in Table 1, the Company is proposing to spend roughly $46 million on active programs, spend $118 million on the proposed Phase VII programs, and collect $97 million on lost revenues from the Phase VII programs, for a total of $262 million from 2018/19 through 2023.

This is roughly 30 percent of the total ten-year budget mandate of $870 million, even though it is covering 60 percent of the years for achieving that mandate. Once lost revenues are removed, the Company proposes to spend about $165 million, barely 19 percent of the ten-year $870 million budget mandate.

[9] The information used to create Table 1 came from Extraordinarily Sensitive Exhibits 3 and 5; however, the specific numbers used in this Table were not identified in those exhibits as extraordinarily sensitive.

Q. How do the Company's budgets compare with the GTSA budget mandates?

A. In Table 2 we present the Company's proposed DSM budgets relative to the GTSA budget mandates. This table presents the Company's proposed DSM budgets, including the budgets for Phases I through VI programs that are still active, and the budgets proposed for Phase VII. This table does not include the lost revenues because these should not be included in program budgets. The Company provides no information on its potential budgets for the four years of 2024 through 2027.

Table 2 also presents the cumulative ten-year $870 million GTSA budget mandate, as well as an illustrative example of how the cumulative mandate could be met with annual budgets. For the illustrative annual budgets, we assume that the proposed budgets are roughly constant over the ten-year period. This would be a logical way to achieve the GTSA budget mandate, because it would allow for a practical, predictable, and consistent implementation of DSM programs. If the Company were to set DSM budgets at a constant amount for ten years to meet the GTSA budget mandate, less the amount it has already spent in 2018, it would need to spend about $94 million per year for nine years. Table 2 also presents the DSM budget shortfall, which is the difference between the Company's proposed budgets and the GTSA mandate.[10]

[10] We calculated the additional budget required to meet the GTSA budget mandate by first assuming a tenth of the GTSA's $870 million ten-year budget mandate is spent in each year, then subtracting out the budget included in the active and proposed programs. For 2028, the additional amount required to meet the $870 million mandate is spent prior to July 1, 2028.

Table 2. Proposed DSM Budgets Relative to the GTSA Budget Mandate ($1000)

Year	Active Programs (Phases I-VI)	Proposed Programs (Phase VII)	Total Proposed Budgets	GTSA Budget Mandate	DSM Budget Shortfall
2018	25,860	-	25,860	25,860	-
2019	20,425	18,196	38,621	93,793	55,172
2020	-	23,929	23,929	93,793	69,864
2021	-	24,588	24,588	93,793	69,206
2022	-	25,406	25,406	93,793	68,388
2023	-	26,289	26,289	93,793	67,505
2024	-	-	-	93,793	93,793
2025	-	-	-	93,793	93,793
2026	-	-	-	93,793	93,793
2027	-	-	-	93,793	93,793
Total	**46,285**	**118,408**	**164,693**	**870,000**	**705,308**

Source: The active and proposed program budgets are from Table 1. The annual GTSA budget mandates are provided for illustrative purposes, as described above.

Table 2 demonstrates that the Company's proposed DSM budgets are well below the GTSA budget mandates. From a cumulative perspective:

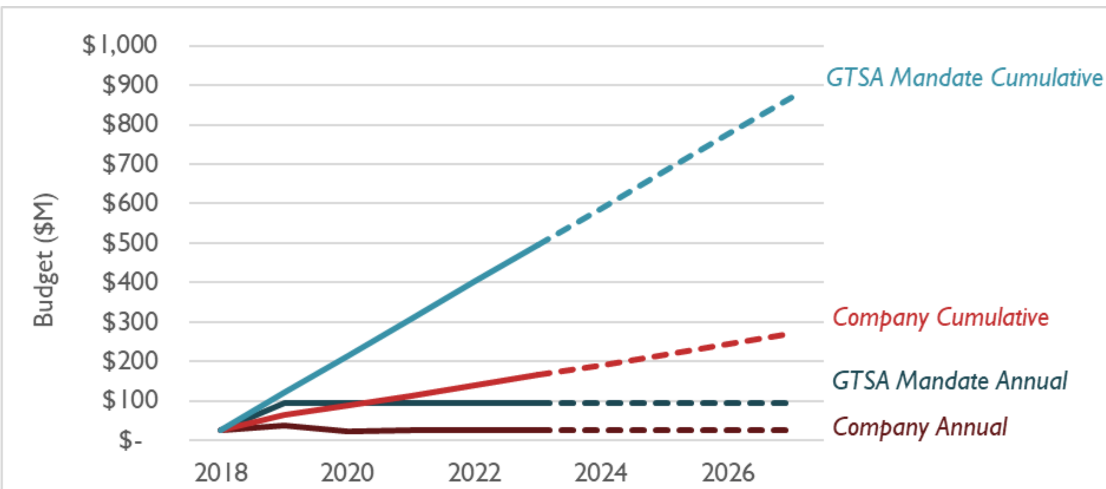
- The Company's proposed budgets for six years are $165 million, which is roughly 19% of the ten-year $870 million GTSA mandate, even though the Company's budgets cover 60% of the GTSA mandates time-period, or 2018-2028..
- The Company's cumulative budgets for six years is $705 million *less* than the cumulative GTSA budgets for ten years. If the Company were to attempt to make up this shortfall in the remaining four years of the GTSA 10-year time period, it would need to expand its budgets (and commensurate program activities) by roughly a factor of four relative to all current phases, and by a factor of five relative to the Phase VII budgets. This would be an extremely impractical and inefficient way to comply with the GTSA budget mandate.

From an annual perspective:

- A more practical, consistent, and predictable budgeting approach would require annual budgets of roughly $93 million. Instead, the Company is proposing to spend roughly $24 million per year on average over the next five years; which is only 26% of the more practical approach.

Figure 5 compares the annual and cumulative budgets proposed by the Company to the GTSA budget mandate, using the information from Table 2. The figure also shows hypothetical annual and cumulative budgets for the years 2024/25 through 2027/28 assuming the Company's budgets in those years remain at the same level as the Company's proposed budget for 2023/24. As indicated, the annual and cumulative budgets proposed by the Company are much lower than those mandated by the GTSA.

Figure 5. Company Budget and GTSA Budget, Annual and Cumulative



Source: Table 2.

Q. Has the Company justified its deviation from the GTSA budget mandate?

A. No. The Company did not offer much explanation for this deviation in its initial filing.[11] In response to discovery requests on this topic, the Company stated:[12]

[11] *See, e.g.*, Direct Testimony of Jarvis Bates at 9, lines 7-14, where progress toward the GTSA budget mandate is addressed, but there is no explanation for why the proposed DSM Program budgets fall short of meeting the mandate or if it plans to meet the mandate in the second half of the ten-year period.

> [I]t is the Company's understanding that the total proposed costs of all energy efficiency programs being put forward in this proceeding will be counted towards the Grid Transformation and Security Act's ("GTSA") requirement that the Company propose programs to spend no less than an aggregate amount of $870 million between July 1, 2018 and July 1, 2028, including spend on continuing and approved energy efficiency programs since the July 1, 2018 effective date of the GTSA. The Company's Application in this proceeding represents of proposed program of energy conservation measures the cost of which total approximately $262 million.

The Company merely restates the budget mandate and fails to explain how its proposed $262 million budget complies with the GSTA budget mandate to propose $870 million over 10 years.

Q. In Table 2 and Figure 5 you present the GTSA budget mandates in equal amounts of $94 million per year. Why do you present the mandate this way?

A. The GTSA specifies a total budget for the years 2018-2028. It does not provide any direction on how to spend the budget each year. Decisions regarding annual DSM budgets are left to the Company to propose and the Commission to review and approve.

In order to reach the cumulative ten-year DSM budget mandate in a way that achieves the other statutory and regulatory requirements, it would be appropriate for annual budgets to be implemented in a way that is consistent, predictable, and practical. Utilities with successful energy efficiency programs have learned that relatively consistent program funding from year-to-year is important for the efficient implementation of programs.[13]

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[12] *See* Exhibit 12.

[13] For example, utilities in Massachusetts and Rhode Island prepare periodic Energy Efficiency Plans where the program budgets and activity levels are relatively stable from year to year.

Ramping programs up and down (or, worse, turning them on and off) creates unnecessary costs and inefficiencies for the Company, its program vendors, and its customers. DSM programs are more efficient if program vendors, trade allies, and customers have a sense of what future budgets and programs will be. It is important that the annual budgets represent a practical path toward meeting the cumulative budget mandate. This issue of providing stable DSM programs over time is further discussed in Section 6 of our testimony.

We are not suggesting that the proposed budgets must be exactly $94 million for each year. There may be good reasons why the budgets should be more or less than this amount, to reflect planning considerations, market conditions, and customer response to the programs. We are suggesting that the Company has an obligation to demonstrate how it will meet the cumulative $870 million mandate through annual budgets, and how those budgets will allow for consistent, predictable, and practical DSM program implementation over time.

Q. Are you confident that your presentation of the Company's DSM budgets is consistent with the information in the Company's proposed DSM Programs?

A. Not entirely. Some of the data was not provided by the Company in its initial filing, so we had to submit several discovery requests to obtain it.[14] Even with the discovery responses, the Company did not clearly provide some of the requested information, and we had to make some assumptions in order to complete our analyses. We recommend the Commission direct the Company to provide more clear and organized data in future

[14] *See, e.g.*, Company's responses to Sierra Club 2-6, 2-14, 2-15, 3-1 through 3-4, attached as Exhibits 6-8, 4, and 9-11, respectively.

filings. At a minimum, the Company should provide data similar to Table 1 and Table 2 on its progress toward the GTSA budget mandate in all future DSM and IRP filings.

4.3. The 2018 IRP and Implications for Energy Efficiency DSM Budgets

Q. Has the Commission recently made findings regarding the Company's obligation to analyze the DSM GTSA budget mandates?

A. Yes. In its recent order on the 2018 IRP the Commission was clear that the Company has an obligation to assess the mandates in the GTSA, including the DSM budget mandate, for Commission review and approval.[15] The Commission found that the 2018 IRP "did not fully comply with the Commission's prior directive to include detailed plans to implement the mandates" contained in the GTSA.[16] The Commission then required the Company to re-run its 2018 IRP analyses, and assess the incremental cost impacts of the GTSA mandates, including the mandate to spend $870 million on energy efficiency programs.[17]

Q. What are the implications of the Commission's 2018 IRP order for the energy efficiency program budgets filed in this docket?

A. All the findings from the Commission's 2018 IRP order are directly applicable to the DSM Programs in this docket, because the energy efficiency program budgets and

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[15] *See Commonwealth ex rel. Virginia Electric and Power Company's Integrated Resource Plan Filing pursuant to Va. Code § 56-597* et seq., Case No. PUR-2018-00065, Order, 4 (December 7, 2018), available at https://tinyurl.com/yc3eutx9.

[16] *Id.* at 4-5.

[17] *Id.* at 5.

savings in this docket are based on those in the 2018 IRP.[18] The Company has not evaluated the energy efficiency budget mandate in the GTSA, and has not proposed a set of programs consistent with that mandate in this proceeding. Therefore, the Commission, consistent with its ruling on Dominion's 2018 IRP, must direct the Company to submit a corrected DSM Filing that addresses the directives in the 2018 IRP order pertaining to energy efficiency programs.

4.4. Conclusions and Recommendations

Q. Please summarize your findings on the proposed DSM Program budgets.

A. Our findings on the proposed DSM Program budgets are as follows.

- The DSM Programs do not meet the provision of Senate Bill 966, the GTSA, requiring the Company to propose DSM budgets of $870 million over the next ten years.
- The DSM Programs are based on those filed by the Company in its 2018 IRP, which was rejected by the Commission for several reasons, including the fact that the Company did not properly analyze the DSM budget mandate in the GTSA.
- The Company's cumulative budgets for six years is $705 million *less* than the cumulative GTSA budgets for ten years. If the Company were to attempt to make up this shortfall in the remaining four years of the time period, it would need to

[18] The Company explains that: "The 2018 IRP represents known DSM assumptions as of February 1, 2018. This filing represents responses received May 11, 2018, in response to a Company issued RFP, and specifically the programs evaluated and selected for inclusion as part of the Company's proposed DSM Phase VII." The Company objected to estimating the difference in MWhs between the filings. *See* Company's response to Sierra Club 5-1, attached as Exhibit 15. However, the 2018 IRP indicates savings of 840 GWh, while the Phase VII programs are projected to save 991 GWh, a difference of 18 percent. Direct Testimony of Deanna Kesler, Schedule 7; Dominion Energy, *Virginia Electric and Power Company's Report of its Integrated Resource Plan*, Case No. PUR-2018-00065, Docket No. E-100, Sub 157 at 91 (May 1, 2018), available at https://tinyurl.com/y9ey3tw9.

expand its budgets (and commensurate program activities) by roughly a factor of five relative to the Phase VII budgets. This would be an extremely impractical way to comply with the GTSA budget mandate.

- A more practical, consistent, and predictable budgeting approach would require annual budgets of roughly $93 million. Instead, the Company is proposing to spend on average roughly $24 million per year over the next five years; which is only 26% of the more practical approach.
- The Company has not been forthcoming or transparent regarding its progress toward the GTSA energy efficiency budget mandate and has significantly overstated what little progress it has made by including lost revenues as a budgetary item.

Q. What are your recommendations regarding the proposed energy efficiency budgets?

A. We recommend that the Commission direct the Company to file corrected DSM Programs that comply with the GTSA mandate of proposing a portfolio of DSM programs with budgets no less than $870 million.

Further, we recommend that the Commission make several important clarifications regarding the DSM Program budgets. These clarifications should apply to the corrected DSM Programs and all future DSM proceedings.

- Direct the Company to provide more transparent and complete documentation of annual DSM program budgets, including all the phases of DSM programs and all the components of the DSM budgets, such as O&M costs, common costs, margin, evaluation, or any other costs.
- Direct the Company to provide annual budgets and clarify that the annual DSM budgets should be large enough to achieve the cumulative ten-year budget mandate and ensure a consistent, predictable, and practical approach to compliance with the GTSA mandate.

- Clarify that the GTSA budget mandates represent a *minimum* budget to be proposed for DSM programs that are reviewed and approved by the Commission.
- Clarify that budgets used for compliance with the GTSA mandates should not include lost revenues from DSM programs.

5. DSM PROGRAM COST-EFFECTIVENESS

5.1. The Cost-Effectiveness Tests

Q. Please describe the standard that is used in Virginia to determine whether DSM programs are cost-effective.

A. The Commission shall approve the recovery of DSM program costs only if it finds that the program is "in the public interest."[19] Virginia statute further defines "in the public interest" as follows:

> "In the public interest," for purposes of assessing energy efficiency programs, describes an energy efficiency program if, among other factors, the Commission determines that the net present value of the benefits exceeds the net present value of the costs as determined by not less than any three of the following four tests: (i) the Total Resource Cost Test; (ii) the Utility Cost Test (also referred to as the Program Administrator Test); (iii) the Participant Test; and (iv) the Ratepayer Impact Measure Test. Such determination shall include an analysis of all four tests, and a program or portfolio of programs shall be approved if the net present value of the benefits exceeds the net present value of the costs as determined by not less than any three of the four tests.[20]

[19] Virginia Code § 56-585.1 A 5c.
[20] Virginia Code § 56-576 (definition of "in the public interest").

In sum, in order to be deemed cost-effective, a DSM program should pass at least three out of four traditional cost-effectiveness tests: The Utility Cost, the TRC, the Participant, and the RIM tests.

Q. Please describe why there are several different tests for assessing cost-effectiveness.

A. Each of the traditional tests provide different information about the cost-effectiveness of a DSM program. Each test is designed to provide costs and benefits from different perspectives:

- The Utility Cost test presents costs and benefits from the perspective of the utility system. In this context, the "utility system" refers to all the costs that a utility incurs to provide services to customers. All these costs are passed on to customers through revenue requirements. Thus, the Utility Cost test represents the perspective of all customers as a whole.
- The Participant test presents costs from the perspective of the DSM program participants.
- The TRC test presents costs and benefits from the perspective of the utility system and the DSM program participants.
- The RIM test presents information about the impact on rates from DSM programs.

Each of these perspectives is a different way of looking at the costs and benefits of DSM programs, because the programs can affect different parties differently. In using these cost-effectiveness tests, it is important to understand what information each test is, and is not, providing.

Q. Please summarize what information each cost-effectiveness test provides.

A. When applied properly, the different cost-effectiveness tests provide the following information:[21]

- *The Utility Cost Test* indicates a DSM program's costs and benefits to the utility system. Because a utility's costs are recovered from ratepayers through revenue requirements, this test indicates the effect of a DSM program on a utility's revenue requirements. The Utility Cost test indicates which energy efficiency programs will result in the lowest present value of revenue requirements. The present value of revenue requirements is an important criterion that commissions throughout the US and Canada use to evaluate all types of utility investments. Therefore, the information provided by this test is very useful for comparing DSM programs with other utility resources and investments.
- *The Participant Test* indicates a DSM program's costs and benefits to the program participants. In theory, this test is intended to ensure that customers will experience net benefits by participating in DSM programs. In practice, participants are almost always better off from energy efficiency programs, because programs are designed to ensure that outcome. Therefore, the information provided by this test is less useful than that provided by the Utility Cost test.
- *The TRC Test* indicates a DSM program's costs and benefits to both the utility system and the program participants. In theory, this test is intended to reflect a broader perspective than just the utility system costs and benefits, by including the impacts on program participants. In practice, participants are almost always better off from energy efficiency programs, because programs are designed to ensure that outcome. Consequently, the information provided by this test is less useful than that provided by the Utility Cost test.

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[21] National Efficiency Screening Project, *National Standard Practice Manual for Assessing the Cost-Effectiveness of Energy Efficiency Resources*, Appendix A (Spring 2017), available at https://tinyurl.com/ycxk6wp2, attached as Exhibit 16.

- *The Rate Impact Measure Test* indicates whether energy efficiency will increase or decrease electricity rates. This test is less useful for informing the decision of which utility energy efficiency programs warrant funding, because it does not provide meaningful information on the magnitude of the rate impact or the critical tradeoff between reduced costs and increased rates.

The proper ways to apply and interpret these tests are described in more detail in the following sections.

Q. You note that some of the tests are less useful than other tests. Does this mean that the less useful tests should not be used for assessing cost-effectiveness in Virginia?

A. No. Our main points are (a) that each test provides different information for determining whether a program is in the public interest, and (b) that when using these tests, it is important to recognize what each test is indicating. While Virginia Code requires utilities to analyze the four tests when assessing cost-effectiveness and requires that a DSM program passes three of the four tests in order to be considered cost-effective, the Commission should nonetheless recognize the implications of each of the tests as a part of its cost-effectiveness evaluation. For example, the Commission should recognize the value of the Utility Cost test in providing the best indication of the ability of DSM programs to reduce costs to utility customers. As another example, the Commission should recognize the limitations of the RIM test and give it less weight in the analysis than the other tests. These points are addressed in more detail below.

5.2. The Utility Cost Test

Q. What do the Utility Cost test results indicate about the cost-effectiveness of the Company's proposed energy efficiency programs?

A. The Company's analysis finds that the DSM Programs are very cost-effective according to the Utility Cost test. The DSM Programs are expected to have a benefit-cost ratio of 3.7 and to provide net benefits of $706 million. Individually, all the programs pass this test.[22]

Q. Do you agree with how the Company applies the Utility Cost test?

A. No, not entirely. The Utility Cost test as applied by the Company does not include some important utility system benefits of energy efficiency programs. The NSPM lists the following set of utility system benefits that should be included in any Utility Cost test, and indeed in any cost-effectiveness test for deciding utility investment levels:[23]

- Avoided energy costs;
- Avoided generation capacity costs;
- Avoided transmission and distribution (T&D) costs;
- Avoided T&D line losses;
- Avoided ancillary services;
- Wholesale market price suppression effects;
- Avoided costs of complying with renewable portfolio standards;
- Avoided environmental compliance costs;

[22] Direct Testimony of Deanna Kesler, Schedule 2.
[23] Exhibit 16 at 22, 50-54.

- Avoided credit and collection costs;
- Reduced risk; and
- Increased reliability.

In her testimony on this issue, without explanation, Ms. Kesler lists only the first two benefits, avoided energy and avoided generation capacity, as being included in the Company's Utility Cost test.[24] It is our understanding that the Company also includes avoided T&D costs and T&D line losses in their energy efficiency cost-effectiveness analysis.[25] This means that several of the utility system benefits are not accounted for in the Company's Utility Cost test.

Q. Are these utility system benefits that are not accounted for by the Company likely to have a significant impact on the cost-effectiveness results?

A. Potentially. It is difficult to assess how much these missing utility system benefits will affect the cost-effectiveness results because the Company has not provided any estimates of them.

However, some of them could be quite large. For example, avoided environmental compliance costs can have a significant impact on DSM cost-effectiveness results. CO_2 cap-and-trade mechanisms, such as the Regional Greenhouse Gas Initiative (RGGI), represent an environmental compliance cost that will eventually be recovered from ratepayers and therefore is a utility system cost that should be included in the Utility Cost test.

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[24] Direct Testimony of Deanna Kesler at 8.

[25] *See* Company's responses to Sierra Club 2-11 and 5-9, attached as Exhibits 17 and 18.

5.3. The Total Resource Cost Test

Q. What do the TRC test results indicate about the cost-effectiveness of the Company's proposed energy efficiency programs?

A. The Company's analysis finds that the DSM Programs are very cost-effective according to the TRC test. The DSM Programs are expected to have a benefit-cost ratio of 2.8 and to provide net benefits of $618 million. Individually, all the programs pass the TRC test.[26]

Q. Do you agree with how the Company applies the TRC test?

A. No. First, the TRC test should include at least all the utility system benefits that are included in the Utility Cost test. All the points made above about utility system benefits that were not properly included by the Company in the Utility Cost test are also relevant to the TRC test. In other words, the Company's application of the TRC test understates some of the utility system benefits of the energy efficiency programs.

Second, the TRC test should include participant benefits as well as participant costs. Participant benefits include both non-energy impacts and other fuel impacts. Non-energy impacts include impacts that are not a part of energy consumption or the energy bill but are nonetheless significant impacts experienced by the program participant. Examples of non-energy impacts include: improved productivity in schools and businesses, improved comfort, improved health and safety, low-income benefits, and more.[27] It is our

[26] Direct Testimony of Deanna Kesler, Schedule 2.
[27] Exhibit 16 at 54-57.

understanding that the Company does not include participant non-energy benefits in its TRC test.[28]

Third, the TRC test should include participant "other fuel impacts," which are the impacts on other fuels beside those provided by the utility delivering the energy efficiency programs.[29] For utilities, like the Company, that are delivering energy efficiency programs funded by electricity customers, other fuel impacts could include decreased (or increased) use of natural gas, oil, propane, or other fuels used for space conditioning or water heating.

Accounting for other fuel impacts is especially important if a utility seeks to implement one-stop-shopping approaches for program delivery; multi-fuel efficiency measures; fuel-neutral efficiency measures; fuel optimization efficiency measures; and strategic electrification measures such as electric heat pumps.[30] The magnitude of other fuel impacts can be quite large and significantly affect the cost-effectiveness results. It is our understanding that the Company does not include other fuel impacts in its TRC test.[31]

In sum, these three omissions—some utility system benefits, the participant non-energy impacts, and the participant other fuel impacts—mean that the Company's TRC test dramatically understates the benefits of its DSM programs.

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[28] Direct Testimony of Deanna Kesler at 8-9; *see also* Company's response to Sierra Club 2-12, attached as Exhibit 19.
[29] Exhibit 16 at 28-29, 56-57.
[30] *Id.* at 28.
[31] *See* Company's response to Sierra Club 2-13, attached as Exhibit 20.

5.4. The Participant Test

Q. What do the Participant test results indicate about the cost-effectiveness of the Company's proposed energy efficiency programs?

A. The Company's analysis finds that the DSM Programs are very cost-effective according to the Participant test. The DSM Programs are expected to have a benefit-cost ratio of 6.0 and to provide net benefits of $1,085 million. Individually, all the programs pass this test.[32]

Q. Do you agree with how the Company applies the Participant test?

A. No. Similar to the TRC test, the Participant test should include all the impacts on program participants, including participant non-energy benefits and other fuel impacts. Consequently, the Company's application of the Participant test understates the benefits to participants of DSM programs.

5.5. The Rate Impact Measure Test

Q. What do the RIM test results indicate about the Company's proposed energy efficiency programs?

A. The Company's analysis finds that most DSM Programs do not pass the RIM test. All the programs are expected to have benefit-cost ratios less than one, except for the Residential Smart Thermostat Demand Response program.[33]

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[32] Direct Testimony of Deanna Kesler, Schedule 2.
[33] Direct Testimony of Deanna Kesler, Schedule 2.

Q. Do you agree with how the Company applies the RIM test?

A. No. The utility system impacts are a fundamental component of the RIM test, as well as the Utility Cost test. Greater utility system benefits will put downward pressure on rate impacts. All the points made above about utility system benefits that were omitted from the Utility Cost test also apply to the RIM test, suggesting that the RIM test, as applied by the Company, overstates rate increases and understates rate decreases.

Q. Do you think that the RIM test should be given little weight when assessing DSM program cost-effectiveness?

A. Yes. There are several reasons why the RIM test should be given vey little weight when assessing DSM program cost-effectiveness. First, the RIM test does not provide useful information regarding what happens to rates as a result of efficiency resource investments. A RIM benefit-cost ratio of less than one indicates that rates will increase (all else being equal) but says little about the magnitude of the rate impact, in terms of the percent (or ¢ per kWh) increase in rates or the percent (or dollar) increase in bills. The RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts.

Second the RIM test is not consistent with economic theory. The RIM test and the Utility Cost test are identical except that the lost revenues of energy efficiency programs are included as a "cost" in the RIM test.[34] It is the recovery of these lost revenues that leads to the rate impacts identified by the RIM test. However, these lost revenues are not a *new*

[34] This can be seen by comparing the equations provided for the two tests in the Direct Testimony of Deanna Kesler, at 8-9.

cost created by investments in DSM programs. Lost revenues require utilities to increase prices in order to recover *existing* costs over fewer sales. These existing costs that would be recovered through rate increases are not caused by the efficiency resources themselves, they are caused by *historical* investments in supply-side resources that become fixed costs. These existing fixed costs are referred to as sunk costs. In economic theory, sunk costs should not be considered when assessing future investments because they are incurred regardless of whether the future investment is undertaken. This is why one of the fundamental principles in the NSPM requires that cost-effectiveness analyses be *forward-looking*, capturing the incremental costs and benefits over the life of the resource.[35]

Third, the RIM test results can be misleading. For an efficiency program with a RIM benefit-cost ratio of less than one, the net benefits (in terms of PV$) will be negative. A negative net benefit implies that the investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM test are not new incremental costs associated with efficiency resources. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales, not as a result of incurring new costs. However, utilities frequently present their RIM test results as negative net benefits, implying that an efficiency program will increase costs, when in fact it will not.

[35] *See* Exhibit 16 at 13.

Fourth, the RIM test violates another principle of the NSPM: that energy efficiency is a utility resource and should be evaluated consistently and comparably with other utility resources. Most, if not all, electricity resources can result in some form of cost-shifting across customers. Applying this criterion only to energy efficiency resources results in a bias relative to other types of resources.

Finally, the RIM test is a fundamentally different test than the other three tests described above. The RIM test provides information about whether there will be any costs shifted from DSM program participants to non-participants. This cost-shifting information is different from cost-effectiveness information. The RIM test conflates both cost-effectiveness and cost-shifting, making it difficult to understand either impact.

Q. Please describe how cost-shifting can occur from DSM programs.

A cost-shift can occur, in those cases where the RIM benefit-cost ratio is less than one, because customers will experience increased rates as a result of the DSM program. Program participants will typically see lower bills despite the higher rates, because of their efficiency savings, but non-participants will experience higher bills as a result of the higher rates. Thus, the concerns about rate increases from DSM programs are essentially concerns about cost-shifting from participants to non-participants.

Q. How is cost-shifting different from cost-effectiveness?

A. Cost-effectiveness analyses and cost-shifting analyses answer different questions. Cost-effectiveness analyses address the economics of the utility system as a whole, by answering the question of which resource option will result in net benefits to the entire system in the future. In cost-effectiveness analyses there is no distinction between who experiences the costs or benefits; the goal is to reduce costs for all. Cost-shifting analyses address the issue of customer equity, by answering the question of how costs might be shifted between customers as a result of different resource options.

Q. Please explain how the RIM test conflates cost-effectiveness and cost-shifting.

A. The RIM test is applied in the context of cost-effectiveness analyses and is assumed to provide information regarding cost-effectiveness. However, by including the lost revenues and related sunk costs in the test, the RIM test does not provide information relevant to cost-effectiveness.

To make matters worse, the RIM test does not provide the cost-shifting information in a meaningful way that can be used by the Company or the Commission. The RIM test will indicate *whether* there might be cost-shifting from DSM programs, but it does not provide any useful indication of the *magnitude* of the cost-shifting. The magnitude of any cost-shifting, or rate increase, might be quite small and reasonable in light of the DSM program benefits in terms of reduced costs.

In sum, by trying to address both cost-effectiveness and cost-shifting in the same test, the RIM test does not provide any useful information on either. For example, a RIM test benefit-cost ratio of 0.7 does not say anything about cost-effectiveness, and does not provide any useful information about the magnitude of cost-shifting.

Q. Are there better ways to analyze the potential cost-shifting from DSM programs?

A. Yes. A long-term rate, bill, and participant (RBP) impact analysis is a much better way to analyze the potential cost-shifting and rate impacts of energy efficiency programs. The

NSPM recommends that a long-term RBP analysis be used instead of the RIM test to analyze rate impacts.[36]

Q. Please describe what you mean by a long-term rate, bill, and participant analysis.

A. A long-term RBP analysis is a forecast of how rates and bills are likely to change as a result of implementing energy efficiency programs. It compares a scenario assuming that no energy efficiency programs are implemented with a scenario assuming a reference case of energy efficiency programs is implemented, and estimates the differences.

Q. How does a long-term RBP analysis compare with a cost-effectiveness analysis using the RIM test?

A. A long-term RBP analysis is very similar to a cost-effectiveness analysis using the RIM test. Both analyses include forecasts of energy efficiency costs and benefits to the utility system, both analysis account for the impacts of lost revenues, and both analyses assess impacts over the full operating lives of efficiency measures.

However, there are some very important differences between the two approaches. The first difference is how the results are presented. The RIM test results are presented as (a) a benefit-cost ratio, where a ratio less than one indicates that rates are likely to increase as a result of the energy efficiency, and (b) the cumulative present value of revenue requirements, where negative results indicate that rates are likely to increase. The long-term RBP results, on the other hand, are presented as actual rate and bill impacts, in terms of percent changes and dollar changes in rates and bills.

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[36] *Id.* at Appendix C.

The second difference is how the results are used. The RIM test is used to assess *whether* an energy efficiency program is likely to increase rates, whereas a long-term RBP analysis indicates *how much* rates are likely to increase from an energy efficiency program.

The third difference is that the RBP analysis includes an assessment of the customer participation in the energy efficiency programs. Program participation information indicates the portion of customers that will experience bill reductions versus bill increases. (Program participants will generally experience bill reductions while non-participants might see rate increases leading to bill increases.)

Taken together, these three factors—rates, bills, and participation—indicate the extent to which customers as a whole will benefit from efficiency resources. Rate increases can be offset by bill reductions and customer participation, thereby mitigating equity concerns.

Q. Why is a long-term RBP analysis a much better way to evaluate the potential rate impacts of energy efficiency programs?

A. A long-term RBP analysis provides information in a format that is much more useful for regulators, utilities, and other stakeholders to assess whether an energy efficiency program is in the public interest. In some cases, cost-effective energy efficiency programs can both reduce costs and increase rates. Regulators need to strike the appropriate balance between how much to increase rates in order to reduce costs. Knowing simply that energy efficiency programs are likely to increase rates does not provide the information necessary for striking this balance. The best way to strike this balance is to compare the amount of costs that might be reduced with the amount that rates might be increased. A long-term RBP analysis will provide this information, but a RIM analysis will not.

Further, a long-term RBP analysis helps to clarify the distinction between a cost-effectiveness analysis and a cost-shifting analyses. A cost-effectiveness analysis indicates which future investments will provide the maximum net benefits in the future, whereas a cost-shifting analysis indicates the extent to which costs might be shifted from program participants to non-participants. In determining whether an energy efficiency program is in the public interest, it is important to evaluate these two issues separately. As noted above, the RIM test conflates these issues, making it difficult to understand either one.

Finally, a long-term RBP analysis will provide useful information regarding customer participation in efficiency programs. Understanding customer participation can help the Commission strike the right balance between increased rates and reduced costs. Also, DSM programs can be designed to increase participation, thereby mitigating equity concerns and providing benefits to a broader range of customers.

Q. Please describe how the Commission used the results of the RIM test in its order on the Company's Phase VI DSM Programs in Case No. PUE-2016-00111.[37]

A. In the Phase VI DSM Order, the Commission reviewed the cost-effectiveness of the Residential Home Energy Assessment and the Residential Heat Pump Upgrade Programs. The Commission compared the net present value (NPV) of the RIM test results to the NPV of the TRC test results to determine whether the costs of the programs to non-participants exceed the benefits of the programs. For the Home Energy Assessment Program, the Commission found that the *negative* NPV of the RIM test results exceeded

[37] *Petition of Virginia Electric and Power Company for approval to implement new, and to extend existing, demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-282.1 A 5 of the Code of Virginia,* Case No. PUE-2016-00111, Final Order (June 1, 2017), available at https://tinyurl.com/y8hzf34x.

the *positive* NPV of the TRC test results. For the Heat Pump Program, the Commission again found that the *negative* NPV of the RIM test results exceeded the *positive* NPV of the results of all three tests. Consequently, the Commission rejected these two programs as not in the public interest.[38]

Q. Do you agree with this approach to evaluating the cost-effectiveness of energy efficiency programs?

A. No. We do not agree with this approach for several reasons. First, this approach is simply a variation of the RIM test. This approach combines the results of the RIM test with the other cost-effectiveness tests, as an alternative way to assess the rate impacts of DSM programs. As such it suffers from all the problems of the RIM test that we describe above. This approach is based on the misperception that lost revenues are equivalent the new costs, inappropriately combines historical and future costs, conflates cost-shifting with cost-effectiveness, and does not provide useful information on either.

Second, this approach used by the Commission is unconventional and is not consistent with the California Standard Practice Manual or the National Standard Practice Manual, and it is not used by any other US state or Canadian province that we know of. This point alone should give the Commission pause about how appropriate it is to use in Virginia.

If the Commission is concerned about the rate impacts of DSM programs, then it should instead rely upon a long-term rate, bill, and participant impact analysis, as described above.

[38] *Id.* at 10-12.

Q. You state above that the RIM test should be given little weight in assessing DSM program cost-effectiveness. What do you mean by this and what does it mean in practice?

A. Utilities are required to "include an analysis of all four tests" when determining program cost-effectiveness.[39] Therefore, the Company should include the RIM test results in its cost-effectiveness analyses, with the corrections that we recommend above. Virginia Code also requires that a DSM program must pass "not less than any three of the four tests" in order to be determined cost-effective and in the public interest.[40] We recommend that the Company give little weight to the RIM test, and instead use the other three tests for the purpose of determining cost-effectiveness. Further, the long-term rate, bill, and participant analysis should be used in parallel with these three tests to consider the rate implications of the DSM programs.

5.6. The 2018 Integrated Resource Plan

Q. What does the Company's 2018 IRP indicate about the cost-effectiveness of the Company's proposed energy efficiency programs?

A. The 2018 IRP fails to properly evaluate the potential for cost-effective energy efficiency resources on the Company's system. Therefore, it provides little information on the cost-effectiveness of the Company's proposed energy efficiency programs.

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[39] 20 VAC 5-304-20.

[40] Virginia Code § 56-576 (definition of "in the public interest").

Q. Please explain why the Company's 2018 IRP fails to properly evaluate the potential for cost-effective energy efficiency programs.

A. The Company modeled five alternative plans in the 2018 IRP, Plans A through E, each based on different CO_2 reduction requirements. The Company assumed that many different resources, including DSM programs, would be included in exactly the same way in each of the alternative plans.[41] In other words, the DSM program budget and savings estimates were held constant in every plan modeled in the 2018 IRP. Consequently, the 2018 IRP provides no information on the cost-effectiveness of energy efficiency resources other than the programs assumed in every plan. This approach to modeling DSM programs represents a significant flaw in the 2018 IRP and renders much of the IRP results inaccurate.

Q. Please explain why the Company's approach to modeling energy efficiency programs is a significant flaw in the 2018 IRP.

A. First, the Company failed to assess the energy efficiency program budget mandates of the GTSA, as required by the Commission in a prior directive. This failure was recognized by the Commission and was one of the reasons why the Commission directed the Company to file a corrected 2018 IRP, as discussed above. An assessment of the GTSA budget mandate would have provided very useful information on the cost-effectiveness of programs consistent with that mandate, and it would have provided very useful information regarding the DSM programs proposed in this docket.

[41] *Commonwealth ex rel. State Corporation Commission, In re: Virginia Electric & Power Company's Integrated Resource Plan filing pursuant to Virginia Code § 56-597* et seq., Case No. PUR-2018-00065, Virginia Electric & Power Company's Report of its Integrated Resource Plan, 11–12 (May 1, 2018), available at https://tinyurl.com/y9ey3tw9.

Second, the Company's energy efficiency modeling approach fails to meet one of the fundamental objectives of integrated resource planning; which is to integrate demand-side and supply-side resources and determine the optimal amount of each. The Company's energy efficiency modeling approach in the 2018 IRP implicitly assumes that its input levels of energy efficiency savings and budgets are the optimal level without testing this assumption.

Q. Please explain why the Company's DSM modeling approach renders much of the IRP results inaccurate.

A. By analyzing a constant amount of energy efficiency savings in every plan in the IRP, the Company has not investigated the potential for reducing the costs of each plan through different levels of energy efficiency. As a result, the IRP does not present an accurate depiction of the costs of any of the plans. Further, as the costs of any one plan increases relative to a reference case, the potential for cost-effective energy efficiency resources should theoretically increase as well. By not accounting for the potential for increased energy efficiency under higher-cost scenarios, the 2018 IRP undervalues energy efficiency resources and overstates the cost of each plan. This problem with the Company's modeling approach is most evident in the context of its analysis of the options for mitigating CO_2 emissions.

Q. Please explain how the problem with the Company's modeling approach affects its analysis of options for mitigating CO_2 emissions.

A. Much of the Company's analysis in the 2018 IRP is dedicated to analyzing different scenarios of CO_2 emission reduction requirements. The Company designed its five alternative plans to include: no CO_2 requirements, three variations on joining the

Regional Greenhouse Gas Initiative (RGGI), and a federal CO_2 program.[42] The Company concluded that all the scenarios for reducing CO_2 emissions will increase electricity costs by as much as $1.54 to $4.04 billion in net present value revenue requirements over the IRP study period.[43] However, these conclusions are inaccurate because of the Company's modeling approach.

Q. Please explain how the 2018 IRP conclusions regarding carbon mitigation options are inaccurate.

A. It is widely recognized that energy efficiency resources are among the lowest-cost and most plentiful resources for reducing carbon emissions. As CO_2 emission requirements become increasingly stringent, energy efficiency resources will become increasingly cost-effective relative to fossil-fueled, supply-side resources. Therefore, any assessment of CO_2 emission reduction requirements should investigate a range of energy efficiency opportunities to identify how to meet those requirements at the lowest cost.

The Company failed to investigate increasing levels of energy efficiency options in its 2018 IRP, and therefore cannot claim that it has identified the least-cost way of complying with different CO_2 emission requirements. By underutilizing low-cost energy efficiency resources, the Company's 2018 IRP significantly overstates the costs of all the alternative plans.

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[42] Dominion Energy, *Virginia Electric and Power Company's Report of its Integrated Resource Plan*, Case No. PUR-2018-00065, Docket No. E-100, Sub 157, at 10 (May 1, 2018), available at https://tinyurl.com/y9ey3tw9.

[43] *Id.* at 13-14.

This overstatement of costs is even greater because of the other resources that the Company held constant in the 2018 IRP. Wind generators, solar facilities, fossil-fueled power plant retirements, alternative purchases from non-utility generators, and alternative power plant life extensions can all help reduce CO_2 emissions, but the Company held many of these types of resources constant across all scenarios in the 2018 IRP. This modeling approach will significantly increase the costs of compliance with CO_2 mandates, and therefore provide incorrect results.

Q. Why are these points about the 2018 IRP relevant to the Company's proposed DSM Programs?

A. The 2018 IRP analyses were used to indicate the cost-effectiveness of the DSM Programs.[44] If the 2018 IRP properly modeled the potential for energy efficiency resources to reduce CO_2 emissions, it would probably have demonstrated that there is a significant amount of *additional* energy efficiency resources that are likely to be cost-effective.

5.7. Conclusions and Recommendations

Q. Please summarize your findings on the cost-effectiveness of the Company's proposed energy efficiency programs.

A. The Company's proposed DSM Programs are highly cost-effective according to the Company analysis, even though the Company does not account for several important energy efficiency benefits.

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[44] In her direct testimony, Ms. Kesler presents the cost-effectiveness results from the "Federal CO_2" scenario from the 2018 IRP. Direct Testimony of Deanna Kesler, Schedule 2.

- The Company's proposed DSM Programs are cost-effective according to the Company's application of the Utility Cost test, the TRC test, and the Participant test. Therefore, the DSM Programs meet the requirement of being cost-effective according to three of the four traditional cost-effectiveness tests.
- The Utility Cost test as applied by the Company does not include some important utility system benefits of energy efficiency programs, including: wholesale market price suppression effects, avoided costs of complying with renewable portfolio standards, avoided environmental compliance costs, avoided credit and collection costs, reduced risk, and increased reliability.
- The TRC test as applied by the Company does not include some important participant benefits, including: participant non-energy benefits and other fuel impacts. The TRC test as applied by the Company also does not include those utility system benefits that are missing from the Utility Cost test, as noted above.
- The Participant test as applied by the Company does not include some important participant benefits, including: participant non-energy benefits and other fuel impacts.
- The RIM test does not provide useful information, is inconsistent with economic theory, is inconsistent with fundamental principles of the NSPM, is misleading, and conflates cost-effectiveness with cost-shifting. Long-term RBP analyses offer a much better way to analyze rate impacts than the RIM test.
- The Company's 2018 IRP did not investigate the full potential for cost-effective DSM programs, because it used a single set of DSM resources in every scenario and therefore did not explore how much additional cost-effective DSM exists. Therefore, the Company's proposed DSM Programs are not based on a robust cost-effectiveness analysis.

Q. What are your recommendations regarding energy efficiency program cost-effectiveness?

A. Cost-effectiveness analyses are a critical aspect of energy efficiency program planning and implementation because they are required by statute, they provide regulators with important information for determining which efficiency programs warrant utility funding, and they can be used to ensure that customers experience net benefits from the programs. We recommend that the Commission make several important clarifications regarding the cost-effectiveness analyses of energy efficiency programs. These clarifications should apply to the corrected DSM Programs and all future DSM proceedings.

- The Company should use the Utility Cost, the TRC, and the Participant tests to evaluate DSM cost-effectiveness as the three tests that a DSM program must pass in order to be cost-effective. However, these tests as applied by the Company should be improved and updated to be consistent with their theoretical definitions and to include all relevant impacts, as described below.
- In applying the Utility Cost test, the Company should include all utility system impacts that are expected to have a material impact on the results. This means adding the following utility system benefits to the test that is currently used by the Company: avoided costs of compliance with environmental regulations; wholesale market price suppression effects; reduced risk; and increased reliability. (If the full amount of utility system impacts is not included in the Utility Cost test, then at a minimum the Commission should recognize that the test will undervalue the benefits of energy efficiency.)
- In applying the TRC test, the Company should include all utility system impacts that are expected to have a material impact on the results, in the same way that they are included for the Utility Cost test. (If the full amount of utility system impacts is not included in the TRC test, then at a minimum the Commission should recognize that the test will undervalue the benefits of energy efficiency.)

- In applying the TRC test, the Company should also include all relevant participant impacts, including other fuel impacts and non-energy impacts. (If all relevant participant impacts are not included in the TRC test, then at a minimum the Commission should recognize that the TRC test will significantly undervalue the benefits of energy efficiency.)
- The avoided cost of compliance with environmental regulations should reflect the most likely scenario for carbon reduction requirements, including the most likely scenario for Virginia joining RGGI. Any assessment of the costs and benefits of compliance with any environmental regulations should assess the full range of energy efficiency opportunities available to determine the optimal level of efficiency resources that can be used to minimize the costs of compliance.
- The RIM test should be given little weight when determining whether DSM programs are cost-effective, either in isolation or by adding its results to the results of the other tests.
- The Company should conduct a long-term rate, bill, and participant impact analysis alongside cost-effectiveness analyses. This analysis should be used in addition to the RIM test to investigate the potential rate impacts of DSM programs.
- The Company should assess the cost-effectiveness of several different amounts of energy efficiency budgets and savings, including budgets consistent with the GTSA mandates, to identify the optimal level of energy efficiency resources available.

6. ADDITIONAL DSM OPPORTUNITITES

6.1. The Company's DSM Potential Study

Q. Has the Company provided evidence that there are more cost-effective efficiency savings available, beyond the savings in the proposed DSM Programs?

A. Yes. The Company completed a potential study in October 2017 (DSM Potential Study) that indicates there are significantly greater savings the Company could achieve through its DSM programs.[45] The DSM Potential Study estimated savings potential for five scenarios for 2018 through 2027, as described below and summarized in Figure 6.[46]

- Technical: The savings that would occur if all measures deemed technically feasible from an engineering perspective were installed. The study estimated about 25,000 GWh of technical savings potential.
- Economic: The savings that would occur if all measures that are cost-effective when compared to supply-side alternatives were installed. The study estimated about 14,000 GWh of economic savings potential.
- 75% Incentive (Achievable): The savings that would occur if the Company provided customer incentives (i.e., rebates) equal to 75% of incremental measure costs. The study estimated about 4,000 GWh of achievable savings potential in this scenario.
- 50% Incentive (Achievable): The savings that would occur if the Company provided customer incentives (i.e., rebates) equal to 50% of incremental measure costs. The study estimated about 3,000 GWh of achievable savings potential in this scenario.

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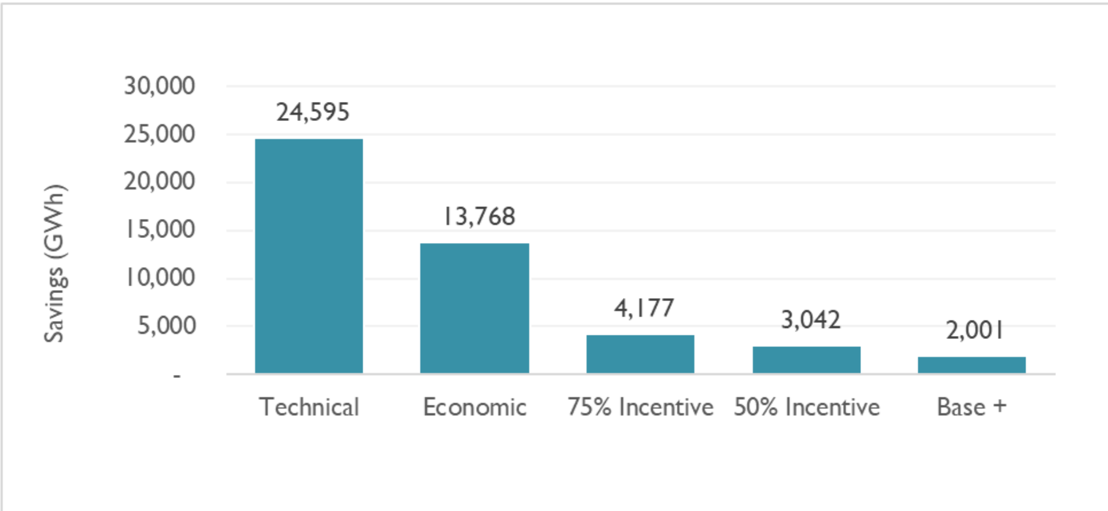
[45] *See* DNV-GL, *Dominion Energy Efficiency Potential Study: 2018 to 2027* (October 17, 2017), attached as Exhibit 21.

[46] *Id.* at 5-7.

- Base +: The savings that would occur if the Company's then-current budgets remained constant, and included all cost-effective measures, even those measures not offered by the Company. The study estimated about 2,000 GWh of savings potential in this base case scenario.

Figure 6. DSM Potential Study Results, Savings Opportunities for 2018-2027



Source: Exhibit 21 at 7.

The Company expects its Phase VII programs to achieve savings of 962 GWh over the six years 2019-2023.[47] This is only 23% of the 75% Incentive scenario from the DSM Potential Study.

Q. How would the energy savings in the proposed DSM Programs compare with the energy savings opportunities from the DSM Potential Study if they were compared over a comparable time period?

A. The proposed DSM Programs cover a period of five years (2019-2023), while the DSM Potential Study covers a period of ten years (2018-2027). In order to put the five-year savings from the proposed DSM Programs on comparable terms with the ten-year savings

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[47] Direct Testimony of Deanna Kesler, Schedule 7.

of the DSM Potential Study, we double the proposed DSM Program savings, from 962 to 1,924 GWh. This amount of savings is 46% of the 4,177 savings of the 75% Incentive scenario in the DSM Potential Study. In other words, the savings in the Company's proposed DSM Programs are less than half of the potential cost-effective savings from the Company's own DSM Potential Study, if applied over a comparable time period.

Q. Is it reasonable to compare the savings from the Company's proposed DSM Programs to the savings opportunities from the 75% Incentive scenario from the DSM Potential Study?

A. Yes. The 75% Incentive scenario is a reasonably achievable scenario that reflects a realistic picture of the potential for cost-effective DSM programs in the Company's territory. This scenario simply represents a more aggressive approach to delivering DSM programs, relative to the 50% Incentive or the Base + scenarios. In many cases, utilities can achieve greater efficiency savings than this scenario by using best practice, state-of-the-art DSM program designs. In fact, the Economic scenario depicted in Figure 6 is a better indication of the full potential for cost-effective energy efficiency programs in the Company's territory than the 75% Incentive scenario.

Q. Has the Company indicated why savings from its DSM Programs are below the DSM Potential Study savings estimates?

A. No. By its own calculations, the Company recognizes that its DSM programs are well below the DSM Potential Study estimates. In its IRP, the Company states: "The energy reductions projected for 2022 in the 2017 Plan were 1,217 GWh. This level of energy reduction represents 40 percent of the amount shown in the 2017 DSM DSM Potential

Study (50% Incentive scenario) for 2022."[48] The Company recognizes it is aiming to achieve less than half of the lowest recommended savings from the DSM Potential Study.

Q. Does the DSM Potential Study provide any evidence that the Company could implement DSM program budgets consistent with the $870 million GTSA budget mandate?

A. Yes. The DSM Potential Study estimates that by 2027 the 50% Incentive scenario would cost about $891 million, which is very close to the GTSA budget mandate.

Q. Does the DSM Potential Study provide any evidence of the amount of money that customers could save if the Company were to implement program budgets consistent with the $870 million GTSA budget mandate?

A. Yes. The DSM Potential Study finds that the 50% incentive scenario would cost roughly $890 million, but save roughly $2,176 million, providing net benefits of $1,286 million, in cumulative present value terms.[49]

6.2. DSM Program Designs and Implementation

Q. Do the Company's active and proposed DSM programs address a broad range of market segments and customer groups?

A. No. The Company's active programs and proposed programs do not address the following key market segments: [50]

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[48] Dominion Energy, *Virginia Electric and Power Company's Report of its Integrated Resource Plan*, Case No. PUR-2018-00065, Docket No. E-100, Sub 157 at 91 (May 1, 2018), available at https://tinyurl.com/y9ey3tw9.

[49] Exhibit 21 at 77-79. These values are from the results of the Utility Cost test.

- New construction for residential and non-residential customers
- Residential heating and/or cooling system replacement
- Residential comprehensive retrofit, including weatherization measures
- An "upstream buydown" approach for residential and non-residential measures, through which incentives are provided to manufacturers and/or distributors to reduce the cost paid by consumers, rather than a rebate paid to the customer directly
- Multi-family for residential and non-residential building and metering configurations, addressing barriers and challenges specific to the multi-family market
- Strategic energy management or continuous energy improvement programs that target and are tailored to the needs of specific non-residential customers groups (e.g., agriculture, retail stores, restaurants, convenience stores)[51]

These programs are frequently included in successful portfolios of energy efficiency programs offered by utilities in other states.[52] By not offering such programs, the Company and its customers will experience lost opportunities, which occur when efficiency measures are not installed when it is most cost-effective to do so (e.g., the construction of a new building or facility, building renovations, and the purchase of new appliances or equipment).

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[50] *See* Company's responses to Sierra Club 3-20 and 4-9, attached as Exhibits 23 and 24 respectively.

[51] The Company responded that certain customer groups such as multi-family and non-residential customers are not excluded from the Company's program. However, the Company seems to adopt a "one size fits all" approach, when customer groups can have different barriers and DSM needs. *See* Company's responses to Sierra Club 4-9 and 4-10, attached as Exhibits 24 and 25.

[52] *See* American Council for an Energy Efficiency Economy, *The New Leaders of the Pack: ACEEE's Fourth National Review of Exemplary Energy Efficiency Programs*, Report U1901, (January 2019), available at: https://aceee.org/research-report/u1901, attached as Exhibit 26.

Further, programs should be designed to provide efficiency savings to all customers to promote the equitable use of efficiency budgets and reduce program non-participants. By not offering programs that are tailored to key market segments—multifamily, new construction, small business customers—the Company fails to serve all customers comprehensively. As more customers participate in energy efficiency programs, more customers will experience program benefits, including net bill reductions. Increasing program budgets will better ensure that all customers who want to participate can participate and increase the portion of customers that experience net benefits from the energy efficiency programs.

Q. Did the DSM Potential Study draw conclusions regarding the measures and programs offered by the Company?

A. Yes. The DSM Potential Study states: "there is additional potential available from measures not currently in Dominion's DSM portfolio. Dominion's past programs have not touched all end uses, so opportunities to start programs targeting those markets."[53] We agree with the DSM Potential Study that there are additional measures and markets the Company could better address through its DSM programs to achieve greater savings.

Q. How can the Company improve the suite of programs offered to customers?

A. We recommend the Company work with stakeholders, consistent with the process dictated in the GTSA[54] to design a comprehensive suite of programs that address all eligible customer segments and offer measures that address all end use technologies.

[53] Exhibit 21 at 7.
[54] Senate Bill 966, 2018 Virginia General Assembly ¶ 15 (March 1, 2018).

American Council for an Energy Efficiency Economy (ACEEE) recently released a report that could assist the Company in designing a more comprehensive suite of programs.[55] In the report, ACEEE examined:

> leading efforts in residential, commercial, and industrial customer sectors to facilitate the borrowing and adapting of strategies across sectors, end uses, and technologies. Disseminating examples of effective designs is increasingly important in today's industry environment. The need for improvement is growing, driven by factors such as regulatory requirements to meet aggressive energy savings targets in the context of increasingly fast-changing markets—both as codes and standards are adopted for existing technology and as new technology and new market opportunities emerge. This report facilitates peer learning to meet that demand.[56]

Q. Are there other ways the programs could be improved?

A. Yes. A side-effect of the phased approach to program planning is that programs may not be continuous.[57] For example, the Residential Income and Age Qualifying Home Improvement program recently went through a re-launch, which resulted in increased costs to ratepayers to restart the program, resulted in the program being unavailable to customers for six months, and impacted vendor and contractor implementation.[58]

In addition, the Company claims that its DSM Phase VII Non-residential Lighting Systems & Controls Program, the Non-residential Heating and Cooling Efficiency

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[55] *See* Exhibit 26.
[56] *See id.* at 2-3.
[57] *See* Company's response to Sierra Club 3-16, attached as Exhibit 28.
[58] *See* Company's response to Sierra Club 3-14, attached as Exhibit 29.

Program, and the Window Film Program are not extensions of the Company's DSM Phase III Programs.[59] However, the proposed programs for Phase VII are conceptually similar, and even have the same name across phases, as the Phase III programs.

Q. What impact do program re-launches have on implementation of energy efficiency resources?

A. As mentioned above, any interruption in efficiency program delivery can hinder the development of energy efficiency thereby reducing savings in several ways, including:

- Trade allies may not be able to maintain stable business levels with abrupt cessations in demand for their services. Even the perception of fluctuating demand for their services may limit trade ally interest and commitment.
- Utility management, program planners, and program implementers will have a difficult time committing to a sustained level of activity if they anticipate fluctuations or interruptions in energy efficiency program requirements.
- Customers may become frustrated or disillusioned with efficiency programs if they are denied access to programs due interruptions, delay, or short program durations. The importance of avoiding this outcome cannot be overstated, as satisfied customers are an essential aspect of implementing energy efficiency programs. In addition, marketing campaigns become inefficient, and possibly misleading, if programs are significantly delayed or interrupted.

Q. How can the Company improve the continuous delivery of programs?

A. At a minimum, the Company should propose program renewals for Commission review such that there are no gaps in program implementation due to regulatory review. Prior to terminating a program, the Company should evaluate whether savings potential remains

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[59] *See* Company's response to Sierra Club 3-15, attached as Exhibit 30.

for the targeted customer group or measure, and modify the program as needed to achieve those savings. Across phases, the Commission should allow the Company to make relatively minor modifications to implementation and customer incentives for programs that target the same customer group and end uses—such as with the Non-residential Lighting Systems & Controls Program, the Non-residential Heating and Cooling Efficiency Programs from Phase III to Phase VII.

Further, for future filings, the Commission should consider moving away from a phased program approach to a comprehensive, multi-year planning process with a suite of programs reviewed and approved on the same schedule. Such a structure could provide opportunities for regulatory review within the multi-year plan term for significant proposed program modifications so the Commission could ensure ratepayer benefits continue to be achieved. This would streamline regulatory review and allow for more timely and complete program implementation. It would also be more consistent with how other jurisdictions approach multi-year planning cycles.[60]

6.3. Comparison with DSM in Other States

Q. How do the Company's savings levels compare with other states?

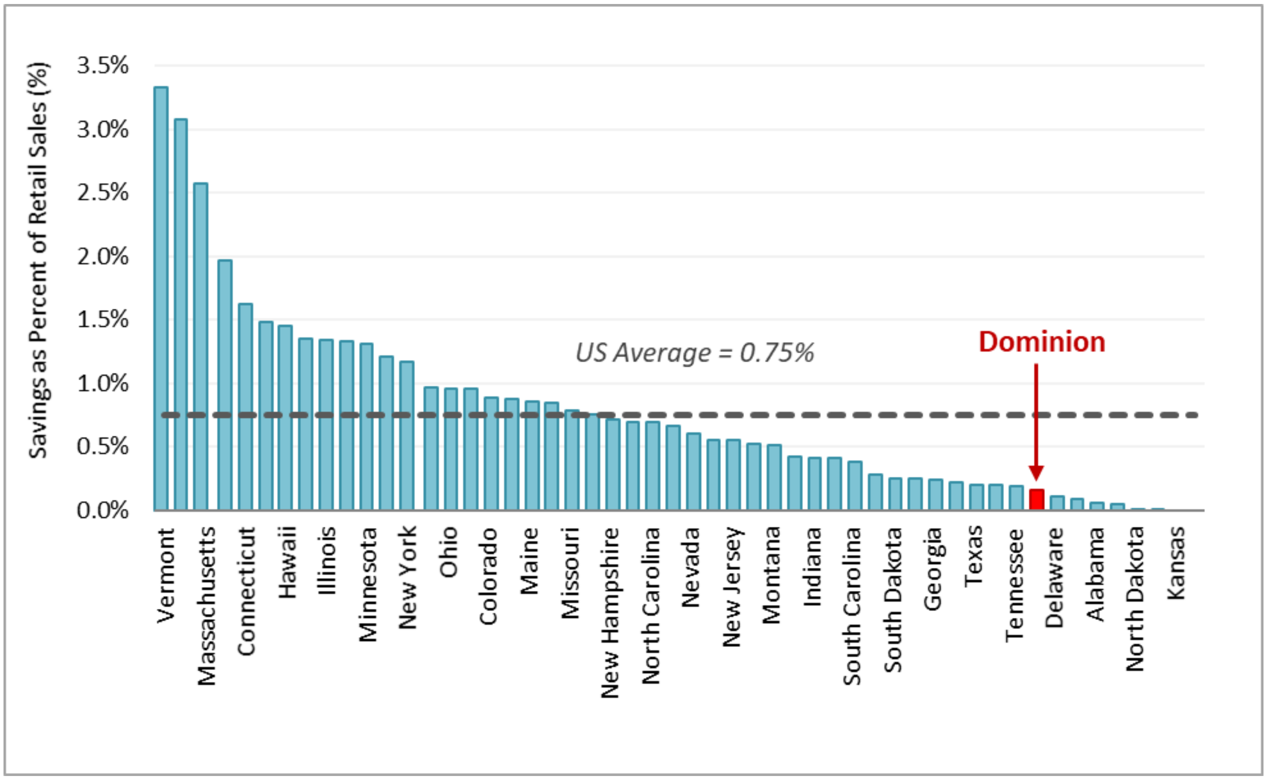
A. The Company is far behind other states in the level of savings achieved from ratepayer funded energy efficiency programs. Figure 7 summarizes 2017 annual savings as a percent of retail sales for all 50 US states and the District of Columbia. Instead of

[60] *See* ACEEE, *Energy Efficiency Resource Standards*, available at https://database.aceee.org/state/energy-efficiency-resource-standards, attached as Exhibit 27.

showing Virginia, we provide the Company's savings as a percent of sales based on US Energy Information Administration (EIA) data.[61]

On average, states save 0.75 percent of sales, with many states achieving upwards of 1 or even 2 percent of sales. The Company saves 0.15 percent of sales; only one-fifth of what states across the US save on average. The Company ranks at the bottom of states, ahead of just seven other states.

Figure 7. 2017 Annual Savings as a Percent of Sales, All State Comparison



Sources: ACEEE, The 2018 State Energy Efficiency Scorecard, *Report U1808 at 29 (October 2018), available at: https://aceee.org/research-report/u1808; US Energy Information Administration, From EIA-861, 2017,*

[61] Our savings as a percent of sales analysis includes the Company's residential and commercial sales reported in EIA 861, which might include sales from customers who are not eligible to participate in the Company's DSM programs. We asked the Company for sales related to eligible customers, but the Company objected to the question. *See* Company's response to Sierra Club 4-6, attached as Exhibit 31.

Sales to Ultimate Customers and Energy Efficiency, available at https://www.eia.gov/electricity/data/eia861/.[62]

Q. How do the Company's savings levels compare with savings levels in other states in the region?

A. The Company's savings levels are much lower than savings levels in other states in the region. In Figure 8 we compare annual savings as a percent of sales from 2012-2023 for the Company, and for 2012-2017 for North Carolina, Pennsylvania, the District of Columbia, and New Jersey. For the Company we summed residential and commercial sales and savings from EIA data for 2012-2017, and for 2019-2023 we divide the Company's projected savings by 2018 sales (assuming 2018 sales remain constant for the period). For 2018, we linearly interpolated between 2017 and 2019. For the other states, we used ACEEE Scorecard data.[63]

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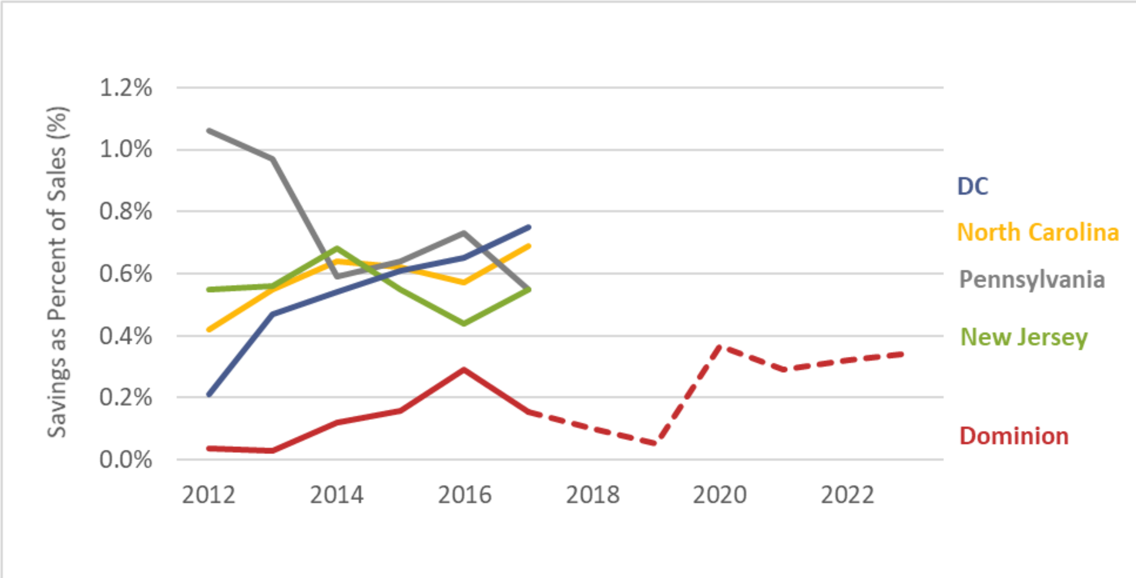
[62] *See* Exhibits 33, 32, respectively.

[63] For 2019-2023, we use the savings as presented for each year in the Direct Testimony of Deanna Kesler, Schedule 7. We assume these savings are on a fiscal year but have presented them here as calendar years to be consistent with historical values and for ease of reference. We also note that savings in 2019 are significantly lower than other years; 2019 savings are only 0.05 percent of sales while other years average savings of 0.2 percent of sales. Our analysis is based on the data provided in Direct Testimony of Deanna Kesler, Schedule 7, which likely only includes a half year of savings.

Figure 8. Savings as a Percent of Sales, Regional State Comparison



Sources: ACEEE Scorecards from 2013 through 2018, available at https://aceee.org/state-policy/scorecard; US Energy Information Administration, From EIA-861, 2017, Sales to Ultimate Customers and Energy Efficiency, available at https://www.eia.gov/electricity/data/eia861/; Direct Testimony of Deanna Kesler, Schedules 1 and 7.[64]

Other states in the region have consistently saved more than the Company. From 2012 to 2017, other states averaged savings of about 0.6 percent of sales, while the Company averaged only 0.13 percent of sales. The Company's projected savings for 2019-2023 are greater than its historical savings, averaging 0.33 percent of sales. Even with this increase in savings over historical results, the Company's proposed DSM Programs continue to be well behind other states in the region.

This analysis further supports our previous conclusions that there is more potential the company could achieve with increased DSM budgets. The Company could easily double or triple the amount of savings it is targeting through its DSM programs to achieve savings levels more consistent with other utilities.

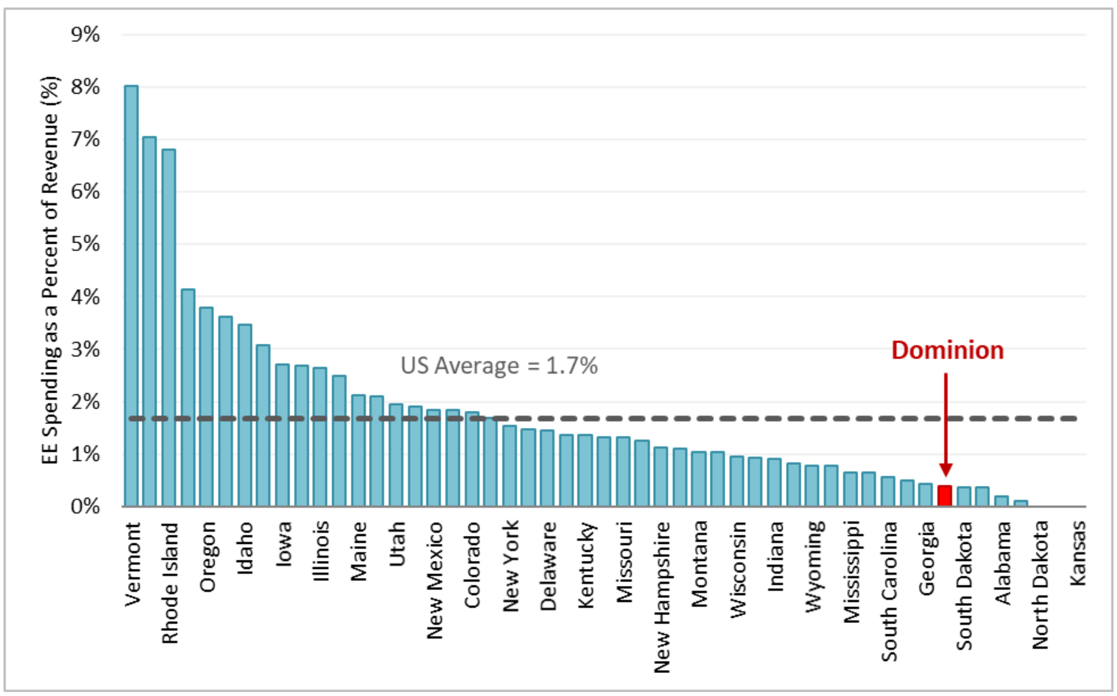
[64] *See* Exhibits 32-33.

Q. How do the Company's DSM budget levels compare with other states?

A. The Company spends far less on DSM programs than other states. Figure 9 summarizes 2017 annual spending as a percent of revenue for all 50 US states and the District of Columbia. Instead of showing Virginia, we provide the Company's spending as a percent of revenue as provided in discovery.

On average, states spend 1.7 percent of utility revenue on energy efficiency programs. The Company spent 0.35 percent of revenue; about one-quarter of what states on average spend. The Company ranks at the bottom of states, ahead of just seven other states.

Figure 9. 2017 Annual Spending as a Percent of Revenue, All State Comparison



Sources: ACEEE, The 2018 State Energy Efficiency Scorecard, *Report U1808 at 28 (October 2018), available at: https://aceee.org/research-report/u1808; Company's response to Sierra Club 4-8.*[65]

[65] *See* Exhibit 34.

Q. How do the Company's DSM budgets compare with DSM budgets in other states in the region?

A. The Company's DSM program budgets are much lower than the DSM budgets in other states in the region. In Figure 10 we compare spending as a percent of revenue for from 2012-2023 for the Company, for 2012-2017 for the same four states used to compare savings levels, and for 2018-2023 for the GTSA $870 million budget mandate. For the Company we used the spending as a percent of revenue provided by the Company in discovery for 2012-2017,[66] and for 2019-2023 we divide the Company's projected spending by the Company's 2017 revenue (assuming 2017 revenue remains constant for the period).[67] For 2018, we linearly interpolated between 2017 and 2019. For the other states, we used ACEEE Scorecard data.[68] For the $870 million budget mandate, we subtract the Company's expected 2018 spending[69] from the $870 million budget mandate and divide the remaining budget by 9 years.

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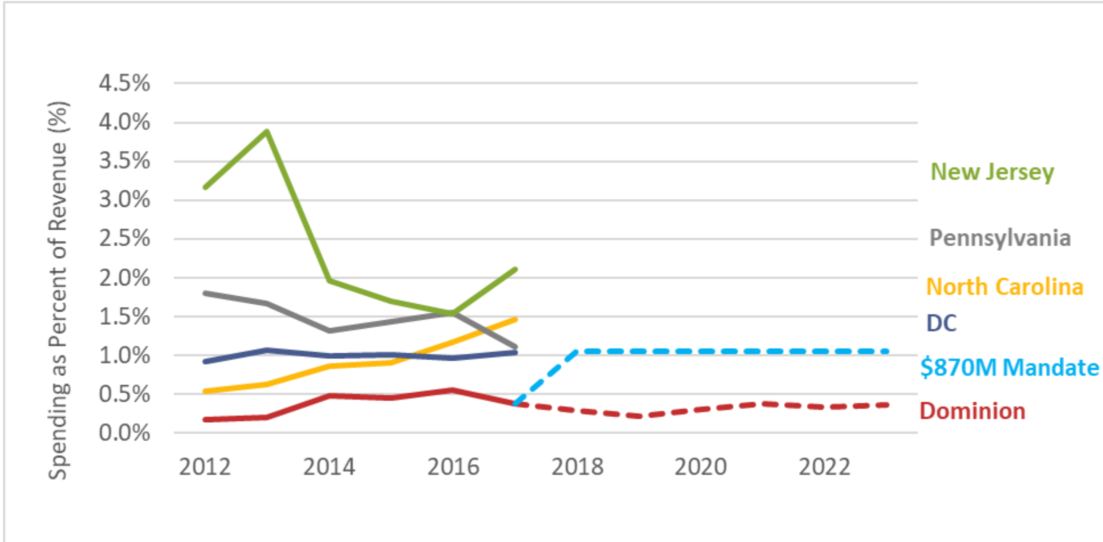
[66] *See* Company's response to Sierra Club 4-8, attached as Exhibit 35.

[67] To estimate the Company's 2017 revenue, we used the Company's 2017 actual spending from Schedule 46B, Statement 8, Grand Total with Electric Vehicles (which is an Extraordinarily Sensitive number) and divided it by the 2017 spending as a percent of revenue from the Company's response to Sierra Club 4-8, Exhibit 35.

[68] For 2019-2023, we use the spending as presented for each year in Exhibit 3 (Extraordinarily Sensitive). We assume spending is on a fiscal year but have presented them here as calendar years to be consistent with historical values and for ease of reference.

[69] As presented in Exhibit 5 (Extraordinarily Sensitive).

Figure 10. Spending as Percent of Revenue, Regional State Comparison



Sources: ACEEE Scorecards from 2013 through 2018, available at https://aceee.org/state-policy/scorecard; Company's response to Sierra Club 4-8; Schedule 46B, Statement 8; Attachment Staff Set 1-02 (JEB) (Extraordinarily Sensitive); Attachment Sierra Club Set 4-13 (Extraordinarily Sensitive).[70]

Other states in the region have consistently spent more than the Company. From 2012-2017, other states averaged spending about 1.45 percent of revenue, while the Company only averaged 0.37 percent of revenue. The Company's projected spending for 2019-2023 averages 0.31 percent of revenue, which is slightly less than its historical spending average. On both a national and regional level, the Company's historical and projected spending levels are significantly lower than other states.

If the Company increased its budget to be consistent with the $870 million budget mandate, the Company would spend closer to 1 percent of revenue on DSM programs. Such an approach is more consistent with the DSM budgets of its other utilities in the region and provides benefits to ratepayers with minimal bill impacts. The $870 million

[70] *See* Exhibits 34, 35, 3 (Extraordinarily Sensitive), and 5 (Extraordinarily sensitive).

budget mandate results in a reasonable annual spending level relative to spending in other states.

6.4. Conclusions and Recommendations

Q. Please summarize your conclusions regarding additional DSM opportunities available to the Company.

A. We find that there are significant opportunities for achieving cost-effectiveness DSM savings beyond what is included in the proposed DSM Programs.

- The Company's recent DSM DSM Potential Study indicates that there are significantly greater cost-effective efficiency savings available to the Company. If the Company were to maintain the savings from its proposed DSM Programs through 2028 (the end of the DSM Potential Study), then it would achieve savings that are only 63 percent and 46 of the two scenarios that include achievable cost-effective DSM savings.
- The Company could significantly increase DSM program savings and customer participation through better program design. Modifications such as serving all market segments, serving all customer types, and addressing all end-uses would significantly increase the savings and net benefits to customers.
- The energy savings from the Company's proposed DSM Programs are expected to be very small relative to other utilities across the US. The Company is expected to save roughly 0.13 percent of sales each year through DSM programs, while the national average is roughly 0.75 percent of sales, and many utilities are achieving 1.0 percent, 2.0 percent and higher.
- The budgets of the proposed DSM Programs are also very small relative to other utilities across the US. The Company plans to spend roughly 0.4 percent of its revenues on DSM programs, which is well below the national average and well below several utilities in the region. If the Company were to propose DSM

budgets that were consistent with the GTSA budget mandates, then that would equal roughly 1.0 percent of revenues, which is consistent with the US average spending levels.

Q. Please summarize your recommendations regarding additional DSM opportunities available to the Company.

A. We recommend the Commission direct the Company to investigate additional DSM opportunities in the corrected DSM Programs and all future DSM Program filings. These additional opportunities should be investigated with input and review of the stakeholder process required by the GTSA. The additional opportunities should be consistent with (a) GTSA budget mandates; (b) the Company's DSM potential studies; (c) best practices in DSM program design; and (d) savings and budgets consistent with other utilities in the region and the US.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TW/EM – 1

RESUME OF TIM WOOLF

Tim Woolf, Vice President

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twoolf@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

Union of Concerned Scientists, Cambridge, MA. *Energy Analyst*, 1982-1983.

EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
Diploma, Economics, 1991

Tufts University, Medford, MA
Bachelor of Science in Mechanical Engineering, 1982

Tufts University, Medford, MA
Bachelor of Arts in English, 1982

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Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with M. Whited regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in advanced metering infrastructure. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Utah Public Service Commission (Docket No. 14-035-114): Direct, rebuttal, and surrebuttal testimony on the benefit-cost framework for net energy metering. On behalf of Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club. July 30, 2015, September 9, 2015, and September 29, 2015.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony on EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-86): Direct and rebuttal Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project.

On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

ARTICLES

Woolf, T., E. Malone, C. Neme, R. LeBaron. 2014. "Unleashing Energy Efficiency." *Public Utilities Fortnightly,* October, 30-38.

Woolf, T., A. Sommer, J. Nielson, D. Berry, R. Lehr. 2005. "Managing Electricity Industry Risk with Clean and Efficient Resources." *The Electricity Journal* 18 (2): 78–84.

Woolf, T., A. Sommer. 2004. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York." *Local Environment* 9 (1): 89–95.

Woolf, T. 2001. "Clean Power Opportunities and Solutions: An Example from America's Heartland." *The Electricity Journal* 14 (6): 85–91.

Woolf, T. 2001. "What's New With Energy Efficiency Programs." *Energy & Utility Update, National Consumer Law Center*: Summer 2001.

Woolf T., B. Biewald. 2000. "Electricity Market Distortions Associated With Inconsistent Air Quality Regulations." *The Electricity Journal* 13 (3): 42–49.

Ackerman, F., B. Biewald, D. White, T. Woolf, W. Moomaw. 1999. "Grandfathering and Coal Plant Emissions: the Cost of Cleaning Up the Clean Air Act." *Energy Policy* 27 (15): 929–940.

Biewald, B., D. White, T. Woolf. 1999. "Follow the Money: A Method for Tracking Electricity for Environmental Disclosure." *The Electricity Journal* 12 (4): 55–60.

Woolf, T., B. Biewald. 1998. "Efficiency, Renewables and Gas: Restructuring As if Climate Mattered." *The Electricity Journal* 11 (1): 64–72.

Woolf, T., J. Michals. 1996. "Flexible Pricing and PBR: Making Rate Discounts Fair for Core Customers." *Public Utilities Fortnightly,* July 1996.

Woolf, T., J. Michals. 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8 (8): 64–72.

Woolf, T. 1994. "Retail Competition in the Electricity Industry: Lessons from the United Kingdom." *The Electricity Journal* 7 (5): 56–63.

Woolf, T. 1994. "A Dialogue About the Industry's Future." *The Electricity Journal* 7 (5).

Woolf, T., E. D. Lutz. 1993. “Energy Efficiency in Britain: Creating Profitable Alternatives.” *Utilities Policy* 3 (3): 233–242.

Woolf, T. 1993. “It is Time to Account for the Environmental Costs of Energy Resources.” *Energy and Environment* 4 (1): 1–29.

Woolf, T. 1992. “Developing Integrated Resource Planning Policies in the European Community.” *Review of European Community & International Environmental Law* 1 (2) 118–125.

PRESENTATIONS

Woolf, T. 2018. Stakeholder presentation on “Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota: Application of the National Standard Practice Manual to Minnesota*.”* Synapse Energy Economics project for Minnesota Department of Commerce, Division of Energy Resources, supported by the Conservation Applied Research and Development (CARD) Program. St. Paul, Minnesota. September 2018.

Woolf, T. 2018. "Benefit-Cost Analysis for Investments in the Modern Grid: Recent trends in how to determine whether grid modernization investments will deliver value to customers." Smart Money Panel, NARUC Summer Policy Summit. Scottsdale, Arizona.

Woolf, T. 2018. "Benefit-Cost Analysis for New York Energy Investments." Training Session for Earthjustice.

Woolf, T. 2018. "National Standard Practice Manual for Energy Efficiency Cost-Effectiveness." Presentation at the NASUCA 2018 Mid-Year Meeting.

Woolf, T. 2018. "The National Standard Practice Manual and the Value of Energy Efficiency in New York." Presentation on behalf of the Natural Resources Defense Council at the Stakeholder Forum, Case 18-M-0084.

Woolf, T., M. Whited. 2016. “Show Me the Numbers: A Framework for Balanced Distributed Solar Policies.” Presentation for Consumers Union Webinar, December 2016.

Woolf, T. 2016. “Show Me the Numbers: Balancing Solar DG with Consumer Protection.” Public workshop on solar distributed generation for the Federal Trade Commission, June 2016.

Woolf, T. 2016. “Rate Designs for Distributed Generation: State Activities & A New Framework.” Presentation at the NASUCA 2016 Mid-Year Meeting, June 2016.

Woolf, T., M. Whited. 2016. “3rd Annual 21st Century Electricity System Workshop – Implications of Different Rate Designs.” Presentation at the Advanced Energy Economy Institute, April 2016.

Woolf, T., M. Whited. 2016. “Decoupling in Pennsylvania: Advantages, Disadvantages, and Design Issues.” Presentation to Pennsylvania Decoupling Stakeholders, February 2016.

Woolf, T. 2016. “Earnings Impact Mechanisms: Energy Efficiency.” Presentation at the New York REV Technical Conference, January 2016.

Lowry, M. N., T. Woolf. 2015. “Performance-Based Regulation in a High Distributed Energy Resources Future.” Webinar on January 2016.

Woolf, T. 2015. “Performance Incentive Mechanisms: A Catalyst for Change.” Webinar for Power Sector Transformation Group, December 2015.

Woof, T. 2015. “Energy Efficiency Valuation: Boogie Men, Time Warps, and other Terrifying Pitfalls.” Presentation at ACEEE Conference on Energy Efficiency as a Resource, September 2015.

Woolf, T., M. Whited, A. Napoleon. 2015. “Thoughts on How to Design Clean Energy Performance Incentive Mechanisms.” Webinar for the Western Clean Energy Advocates, April 2015.

Woolf, T. 2015. “Properly Valuing the Benefits and Costs of Energy Efficiency.” Presentation at the 2015 National Efficiency Advocates Meeting, April 2015.

Woolf, T. 2015. “Non-Energy Benefits & Efficiency Program Screening.” Presentation for Georgia DSM Work Group, March 2015.

Woolf, T. 2014. “Performance Incentive Mechanisms And Their Role in New Regulatory Models.” Presentation at Acadia Center Conference, Envisioning Our Energy Future, December 2014.

Woolf, T., M. Whited., A. Napoleon. 2014. “Guiding Utility Performance: A Handbook for Regulators.” Webinar for the Western Interstate Energy Board, December 2014.

Woolf, T. 2014. “Planning for Distributed Energy Resources.” Presentation for Advanced Energy Economy Webinar, November 2014.

Woolf, T. 2014. “Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits.” Presentation to NARUC ERE Committee, November 2014.

Woolf, T. 2014. “Presenting the Full Value of Energy Efficiency: Creating a Better Message.” Presentation at Sierra Club Beyond Coal Conference, October 2014.

Woolf, T., C. Neme. 2014. “Regulatory Policies to Support Energy Efficiency in Virginia.” Presentation for the 2014 Virginia Energy Efficiency Workshop, October 2014.

Woolf, T. 2014. “Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits.” Presentation for Advanced Energy Economy Institute, October 2014.

Woolf, T. 2014. “Performance Incentive Mechanisms: Digging Deeper Into Performance-Based Regulation.” Presentation for National Governor’s Association Conference: Utility Business Models That Align with State Clean Energy Goals, September 2014.

Woolf, T. 2014. "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening." Presentation at the ACEEE Summer Study, August 2014.

Woolf, T. 2014. "Cost-Effectiveness of Demand Response." Presentation at MADRI Working Group Meeting #34, July 2014.

Woolf, T. 2014. "Time to Overhaul Our Energy Efficiency Screening Practices." Presentation for U.S. Environmental Protection Agency Energy Efficiency Cost-Effectiveness Webinar, January 2014.

Woolf, T. 2013. "Survey of Energy Efficiency Screening Practices in the Northeast and Mid-Atlantic." Presentation for Northeast Energy Efficiency Partnerships EM&V Forum Annual Public Meeting, December 2013.

Woolf, T. 2013. "Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States." Presentation at the National Association of Regulatory Commissioners Annual Meeting, November 2013.

Woolf, T. 2013. "Energy Efficiency Program Screening: Let's Get Beyond the TRC Test." Presentation for 7th Annual ENERGY STAR Certified Homes Utility Sponsor Meeting, October 2013.

Woolf, T. 2013. "Decoupling in Maine: Why Decoupling is in Consumers' Interest." Presentation for Office of Public Advocate- Decoupling Debate, October 2013.

Woolf, T. 2013. "NHPC Efficiency Screening Initiative: Unleashing the Potential for Energy Efficiency." Presentation for Advocates Meeting, September 2013.

Woolf, T. 2013. "Energy Efficiency: Rate, Bill and Participation Impacts." Presentation for ACEEE's Energy Efficiency as a Resource Conference, September 2013.

Woof, T. 2013. "Energy Efficiency Screening: Challenges and Opportunities." Presentation for NARUC Summer Meeting Consumer Affairs Panel, July 2013.

Woolf, T., R. Sedano. 2013. "Decoupling Overview." Presentation for Finding Common Ground Meeting, July 2013.

Woolf, T. 2013. "Utility Incentives for Energy Efficiency." Presentation for Finding Common Ground Meeting, July 2013.

Woolf, T. 2013. "Energy Efficiency: Rate, Bill and Participation Impacts." Presentation for State Energy Efficiency Action Webinar, June 2013.

Woolf, T., B. Biewald, and J. Migden-Ostrander. 2013. "NARUC Risk Workshop for Regulators." Presentation at the Mid-Atlantic Conference of Regulatory Utility Commissioners, June 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Accounting for 'Other Program Impacts' & Environmental Compliance Costs." Presentation for the Consortium for Energy Efficiency Summer Meeting, May 2013.

Woolf, T. 2013. "Best Practices in Energy Efficiency Program Screening." Presentation at ACI National Home Performance Conference, May 2013.

Woolf, T. 2013. “Utility Shareholder Incentives to Support Energy Efficiency Programs.” Presentation to Common Ground, May 2013.

Woolf, T. 2013. “Energy Efficiency Screening: Accounting for ‘Other Program Impacts’ & Environmental Compliance Costs.” Presentation for Regulatory Assistance Project Webinar, March 2013.

Woolf, T. 2013. “Energy Efficiency: Rates, Bills, Participants, Screening, and More.” Presentation at Connecticut Energy Efficiency Workshop, March 2013.

Woolf T. 2013. “Best Practices in Energy Efficiency Program Screening.” Presentation for SEE Action Webinar, March 2013.

Woolf, T. 2013. “Energy Efficiency: Rates, Bills and Participants.” Presentation for Rhode Island Energy Efficiency Collaborative, February 2013.

Woolf, T. 2013. “Energy Efficiency Screening: Application of the TRC Test.” Presentation for Energy Advocates Webinar, January 2013.

Woolf, T. 2012. “Best Practices in Energy Efficiency Program Screening.” Presentation for American Council for an Energy-Efficient Economy Webinar, December 2012.

Woolf, T. 2012. Indian Point Replacement Analysis: A Clean Energy Roadmap. Presentation for Natural Resource Defenses Council and Environmental Entrepreneurs, November 2012.

Woolf, T. 2012. “In Pursuit of All Cost-Effective Energy Efficiency.” Presentation at Sierra Club Boot Camp, October 2012.

Woolf, T. 2012. “Best Practices in Energy Efficiency Program Screening.” Webinar for Northeast Energy Efficiency Partnerships, September 2012.

Woolf, T., L. Schwartz. “What Remains to be Done with Demand Response? A National Forum from the FERC National Action Plan on Demand Response Tries to Give an Answer.” Presentation at NARUC National Town Meeting on Demand Response, July 2012.

Woolf, T. 2012. “Best Practices in Energy Efficiency Program Screening.” Presentation at NARUC Summer Meetings – Energy Efficiency Cost-Effectiveness Breakfast, July 2012.

Woolf, T. 2012. “Avoided Cost of Complying with Environmental Regulations in MA.” Presentation for Mass Energy Consumer’s Alliance, January 2012.

Woolf, T. 2011. “Energy Efficiency Cost-Effectiveness Tests.” Presentation at the Northeast Energy Efficiency Partnerships Annual Meeting, October 2011.

Woolf, T. 2011. “Why Consumer Advocates Should Support Decoupling.” Presentation at the 2011 ACEEE National Conference on Energy Efficiency as a Resource, September 2011.

Woolf, T. 2011. “A Regulator’s Perspective on Energy Efficiency.” Presentation at the Efficiency Maine Symposium *In Pursuit of Maine’s Least-Cost Energy*, September 2011.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs: The Importance of Analyzing and Managing Rate and Bill Impacts.” Presentation at the Energy in the Northeast Conference, Law Seminar International, September 2010.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs: The Implications of Bill Impacts in Developing Policies to Motivate Utilities to Implement Energy Efficiency.” Presentation to the State Energy Efficiency Action Network, Utility Motivation Work Group, November 2010.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs.” Presentation to the Energy Resources and Environment Committee at the NARUC Winter Meetings, February 2010.

Woolf, T. 2009. “Price-Responsive Demand in the New England Wholesale Energy Market: Description of NECPUC’s Limited Supply-Side Proposal.” Presentation at the NEPOOL Markets Committee Meeting, November 2009.

Woolf, T. 2009. “Demand Response in the New England Wholesale Energy Market: How Much Should We Pay for Demand Resources?” Presentation at the New England Electricity Restructuring Roundtable, October 2009.

Woolf, T. 2008. “Promoting Demand Resources in Massachusetts: A Regulator’s Perspective.” Presentation at the Energy Bar Association, Northeast Chapter Meeting, June 2008.

Woolf, T. 2008. “Turbo-Charging Energy Efficiency in Massachusetts: A DPU Perspective.” Presentation at the New England Electricity Restructuring Roundtable, April 2008.

Woolf T. 2002. “A Renewable Portfolio Standard for New Brunswick.” Presentation to the New Brunswick Market Design Committee, January 10, 2002.

Woolf, T. 2001. “Potential for Wind and Renewable Resource Development in the Midwest.” Presentation at WINDPOWER 2001 in Washington DC, June 7, 2001.

Woolf T. 1999. “Challenges Faced by Clean Generation Resources Under Electricity Restructuring.” Presentation at the Symposium on the Changing Electric System in Florida and What it Means for the Environment in Tallahassee, FL, November 1999.

Woolf, T. 2000. “Generation Information Systems to Support Renewable Portfolio Standards, Generation Performance Standards and Environmental Disclosure.” Presentation at the Massachusetts Restructuring Roundtable on behalf of the Union of Concerned Scientists, March 2000.

Woolf, T. 1998. “New England Tracking System Project: An Electricity Tracking System to Support a Wide Range of Restructuring-Related Policies.” Presentation at the Ninth Annual Energy Services Conference and Exposition in Orlando, FL, December 1998.

Woolf, T. 2000. “Comments of the Citizens Action Coalition of Indiana.” Presentation at Workshop on Alternatives to Traditional Generation Resources, June 2000.

Woolf, T. 1996. “Overview of IRP and Introduction to Electricity Industry Restructuring.” Training session provided to the staff of the Delaware Public Service Commission, April 1996.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the Illinois Commerce Commission's workshop on Restructuring the Electric Industry, August 1995.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the British Columbia Utilities Commission Electricity Market Review, February 1995.

Resume dated September 2018

EXHIBIT TW/EM – 2

RESUME OF ERIN MALONE

Erin Malone, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, May 2016 – Present, *Associate*, June 2013 – April 2016, *Research Associate*, January 2012 – June 2013.

- Assists in the evaluation of energy efficiency program design and implementation, including: efficiency technology assessment; program design and budgeting; cost-benefit analyses; avoided cost analyses; and regulatory policies, including program cost recovery and revenue decoupling.
- Conducts research and performs analysis with a special focus on energy efficiency topics, including: energy efficiency research and development; ratepayer-funded efficiency programs; energy efficiency as a central component in utility integrated resource planning; and the role of efficiency in addressing climate change.
- Creator of several proprietary Excel-based models designed to forecast the impacts of energy efficiency, including its impact on customers' rates and bills, expected savings and benefits, and budget forecasting and reporting.

Massachusetts Department of Public Utilities, Boston, MA. *Economist in Electric Power Division*, July 2008 – December 2011.

- Specialized in the review of electric utilities' energy efficiency activities.
- Established efficiency policy by recommending decisions to the Commission on issues related to cost-effectiveness, cost-recovery, and utility performance incentives. Managed timely approval of Massachusetts utilities' 2008-2012 efficiency plans and 2006-2010 efficiency reports by analyzing program implementation and reviewing evaluation studies.
- Created a model that analyzes all impacts of efficiency on consumers' rates and bills. Led stakeholder working groups, and investigated energy efficiency as a central component in utility integrated resource planning.

EDUCATION

Boston College, Chestnut Hill, MA
Bachelor of Arts in Economics, 2008. *Cum Laude*.

LEED Green Associate Accreditation, March 2012

PUBLICATIONS

Knight, P., D. Goldberg, E. Malone, A. S. Hopkins, D. Hurley. 2018. *Getting SMART: Making sense of the Solar Massachusetts Renewable Target (SMART) program*. Prepared for Cape Light Compact.

Malone, E., T. Woolf, D. Goldberg. 2018. *Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota: Application of the National Standard Practice Manual to Minnesota.* Conservation Applied Research and Development (CARD) Report. Prepared by Synapse Energy Economics for Minnesota Department of Commerce, Division of Energy Resources.

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics for Rhode Island Office of Energy Resources.

Whited, M., E. Malone, T. Vitolo. 2016. *Rate Impacts on Customers of Maryland's Electric Cooperatives: Impacts on SMECO and Choptank Customers*. Synapse Energy Economics for Maryland Public Service Commission.

Malone, E., W. Ong, M. Chang. 2015. *State Net-to-Gross Ratios: Research Results and Analysis for Average State Net-to-Gross Ratios Used in Energy Efficiency Savings Estimates*. Synapse Energy Economics for the United States Environmental Protection Agency.

Woolf, T., K. Takahashi, E. Malone, A. Napoleon, J. Kallay. 2015. *Ontario Gas Demand-Side Management 2016-2020 Plan Review.* Synapse Energy Economics for the Ontario Energy Board.

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Massachusetts Department of Public Utilities (DPU 16-169): Oral testimony regarding National Grid's petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. March 8-9, 2017.

Massachusetts Department of Public Utilities (DPU 16-169): Direct testimony of Tim Woolf and Erin Malone regarding Nation Grid's petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. November 2, 2016.

Massachusetts Department of Public Utilities (DPU 16-127): Testimony regarding program results and cost-effectiveness inputs in the Cape Light Compact's 2013-2015 Energy Efficiency Three-Year Term Report. On behalf of the Cape Light Compact. February 10, 2017.

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EXHIBIT TW/EM – 3

STAFF SET 1-02 ATTACHMENT (JEB)

PUBLIC VERSION

Virginia Electric and Power Company
Case No. PUR-2018-00168
Virginia State Corporation Commission Staff
First Set

The following response to Question No. 2 of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on October 17, 2018 has been prepared under my supervision.

Jarvis E. Bates
Energy Conservation Compliance Consultant
Dominion Energy Virginia

Question No. 2

Please provide a copy of all schedules in electronic excel format, with formulas intact.

Response:

See Extraordinarily Sensitive Attachment Staff Set 1-2 (JEB). Extraordinarily Sensitive Attachment Staff Set 1-2 (JEB) contains extraordinarily sensitive DSM Contracts and Prices information, as noted by green shading, and is being provided to the Commission Staff subject to the conditions in 5 VAC 5-20-170, the Company's Motion for Entry of a Protective Ruling and Additional Protective Treatment filed on October 3, 2018 in Case No. PUR-2018-00168, and the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information issued on October 23, 2018 in Case No. PUR-2018-00168.

Demand Side Management (DSM)
Projected Cost Summary - System
Program & Common Costs
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Exhibit No.____
Witness JEB
Schedule 46B
Statement 1

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	DSM Programs (O&M)	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1–32	[redacted]													
33	Pilot (O&M)													
34–36	[redacted]													
37	Programs and Pilot (O&M)													
38	Program & EV Pilot Total	4,431,951	4,431,951	4,431,951	4,373,615	4,373,615	4,373,615	3,677,957	3,677,957	3,677,957	3,677,957	3,677,957	3,743,798	48,550,279
39														
40	Common Costs (O&M)													
41–42	[redacted]													
43	Other	11,867	11,867	11,867	11,867	11,867	11,867	12,318	12,318	12,318	12,318	12,318	12,318	145,110
44	Common Costs Total	199,092	199,092	199,092	199,092	199,092	199,092	205,050	205,050	205,050	205,050	205,050	205,050	2,424,857
45														
46	Program and Common Costs Total	4,631,043	4,631,043	4,631,043	4,572,707	4,572,707	4,572,707	3,883,007	3,883,007	3,883,007	3,883,007	3,883,007	3,948,848	50,975,136
47														
48	Notes:													
49	1 System = Total of All Jurisdictions													
50	2 Res. = Residential; Com. = Commercial; Non Res = Non Residential													
51	3 Data excludes Margin, Lost Revenues, Test Year Actuals True-up													
52														
53														
54														
55														

Demand Side Management
Program Penetrations/Participants - Counts & Percentages
System and Virginia Jurisdiction
Calendar Years

Row				Incremental Year 2019	Incremental Year 2020
	System Counts:				
1	Programs DSM Phase II - System				
2	1	Com.	Distributed Generation (DG)	8	9
3					
4	Programs DSM Phase III - System				
5	1	Non Res.	Window Film (square feet)	-	-
6	2	Non Res.	Heating & Cooling Efficiency	-	-
7	3	Non Res.	Lighting Systems & Controls	-	-
8					
9	Programs DSM Phase IV - System				
10	1	Res.	Income and Age Qualifying Home Improvement	4,500	4,500
11					
12	Programs DSM Phase V - System				
13	1	Non Res.	Qualifying Small Business Improvement	990	1,147
14					
15	Programs DSM Phase VI - System				
16	1	Non Res.	Prescriptive	456	456
17					
18	Programs DSM Phase VII - System				
19	1	Res.	Appliance Recycling	5,225	9,500
20	2	Res.	Customer Engagement	255,000	244,000
21	3	Res.	Efficient Products Marketplace	2,972,475	2,312,132
22	4	Res.	Home Energy Assessment	11,030	30,357
23	5	Res.	Smart Thermostat - DR	6,808	20,673
24	6	Res.	Smart Thermostat - EE	9,071	24,910
25	7	Non Res.	Lighting Systems & Controls	333	665
26	8	Non Res.	Heating & Cooling Efficiency	350	700
27	9	Non Res.	Window Film (square feet)	68,400	133,950
28	10	Non Res.	Small Manufacturing	35	70
29	11	Non Res.	Office	42	84
30					
31					
32	Virginia Jurisdiction Counts:				
33					
34	Programs DSM Phase II - Virginia Jurisdiction				
35	1	Com.	Distributed Generation (DG)	8	9
36					
37	Programs DSM Phase III - Virginia Jurisdiction				
38	1	Non Res.	Window Film (square feet)	-	-
39	2	Non Res.	Heating & Cooling Efficiency	-	-
40	3	Non Res.	Lighting Systems & Controls	-	-
41					
42	Programs DSM Phase IV - Virginia Jurisdiction				
43	1	Res.	Income and Age Qualifying Home Improvement	4,230	4,230
44					
45	Programs DSM Phase V - Virginia Jurisdiction				
46	1	Non Res.	Qualifying Small Business Improvement	931	1,078
47					
48	Programs DSM Phase VI - Virginia Jurisdiction				
49	1	Non Res.	Prescriptive	429	429
50					
51	Programs DSM Phase VII - System				
52	1	Res.	Appliance Recycling	5,225	8,930
53	2	Res.	Customer Engagement	255,000	229,360
54	3	Res.	Efficient Products Marketplace	2,972,475	2,173,404
55	4	Res.	Home Energy Assessment	11,030	28,536
56	5	Res.	Smart Thermostat - DR	6,808	19,433
57	6	Res.	Smart Thermostat - EE	9,071	23,415
58	7	Non Res.	Lighting Systems & Controls	333	625
59	8	Non Res.	Heating & Cooling Efficiency	350	658
60	9	Non Res.	Window Film (square feet)	68,400	125,913
61	10	Non Res.	Small Manufacturing	35	66
62	11	Non Res.	Office	42	79
63					
64					

Exhibit No.____
Witness JEB
Schedule 46B
Statement 2

Virginia Jurisdiction Percentages:

Programs DSM Phase II - Virginia Jurisdiction				
1	Com.	Distributed Generation (DG)	100.0000%	100.0000%
Programs DSM Phase III - Virginia Jurisdiction				
1	Non Res.	Window Film (square feet)	94.0000%	94.0000%
2	Non Res.	Heating & Cooling Efficiency	94.0000%	94.0000%
3	Non Res.	Lighting Systems & Controls	94.0000%	94.0000%
Programs DSM Phase IV - Virginia Jurisdiction				
1	Res.	Income and Age Qualifying Home Improvement	94.0000%	94.0000%
Programs DSM Phase V - Virginia Jurisdiction				
1	Non Res.	Qualifying Small Business Improvement	94.0000%	94.0000%
Programs DSM Phase VI - Virginia Jurisdiction				
1	Non Res.	Prescriptive	94.0000%	94.0000%
Programs DSM Phase VII - System				
1	Res.	Appliance Recycling	100.0000%	94.0000%
2	Res.	Customer Engagement	100.0000%	94.0000%
3	Res.	Efficient Products Marketplace	100.0000%	94.0000%
4	Res.	Home Energy Assessment	100.0000%	94.0000%
5	Res.	Smart Thermostat - DR	100.0000%	94.0000%
6	Res.	Smart Thermostat - EE	100.0000%	94.0000%
7	Non Res.	Lighting Systems & Controls	100.0000%	94.0000%
8	Non Res.	Heating & Cooling Efficiency	100.0000%	94.0000%
9	Non Res.	Window Film (square feet)	100.0000%	94.0000%
10	Non Res.	Small Manufacturing	100.0000%	94.0000%
11	Non Res.	Office	100.0000%	94.0000%

Notes:

1 Phase II Programs (except DG) for the Virginia Jurisdictional rate year only include EM&V costs since the programs are not continuing.
2

Virginia Jurisdiction				
	Other	Electric Vehicle (EV) Pilot	100.0000%	100.0000%

Notes:

1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential
2 Data excludes Margin
3 Data excludes Lost Revenues

1	4,238.00
	8.00
	52975.0%

Demand Side Management
Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	Phase II Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	1 Com. [redacted]													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase II Programs	109,942	109,942	109,942	51,605	51,605	51,605	58,244	58,244	58,244	58,244	58,244	124,085	899,945
10														
11	[redacted]													
12														
13														
14	Notes:													
15	1 Res. = Residential; Com. = Commercial													
16	2 Data excludes Margin													
17	3 Data excludes Lost Revenues													
18														

Demand Side Management

Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
			2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
		Phase III Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	1 Non Res.	[redacted]													
2															
3															
4															
5															
6															
7															
8	2 Non Res.														
9															
10															
11															
12															
13															
14															
15	3 Non Res.														
16															
17															
18															
19															
20															
21															
22															
23		Total Phase III Programs	21,667	21,667	21,667	21,667	21,667	21,667	-	-	-	-	-	-	130,000
24															
25															
26	Notes:														
27		1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
28		2 Data excludes Margin													
29		3 Data excludes Lost Revenues													
30															

Demand Side Management
Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Exhibit No.____
Witness JEB
Schedule 46B
Statement 3

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	Phase IV Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	1 Res. [redacted]													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase IV Programs	348,345	348,345	348,345	348,345	348,345	348,345	368,281	368,281	368,281	368,281	368,281	368,281	4,299,757
10														
11														
12														
13														
14	Notes:													
15	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
16	2 Data excludes Margin													
17	3 Data excludes Lost Revenues													
18														

Demand Side Management

Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
Row		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	[redacted]													
1	1 Non Res.													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase V Programs	646,805	646,805	646,805	646,805	646,805	646,805	737,128	737,128	737,128	737,128	737,128	737,128	8,303,598
10														
11														
12														
13														
14	Notes:													
15	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
16	2 Data excludes Margin													
17	3 Data excludes Lost Revenues													
18														

Demand Side Management
Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Exhibit No.____
Witness JEB
Schedule 46B
Statement 3

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	Phase VI Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	1 Non Res. [redacted]													
2														
3														
4														
5														
6														
7														
14														
15														
16	Total Phase VI Programs	527,952	527,952	527,952	527,952	527,952	527,952	528,035	528,035	528,035	528,035	528,035	528,035	6,335,920
17														
18														
19														
20														
21	Notes:													
22	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
23	2 Data excludes Margin													
24	3 Data excludes Lost Revenues													
25														

Demand Side Management
Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
			2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
		Phase VII Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	1 Res.	[redacted]													
2															
3															
4															
5															
6															
7															
8	2 Res.														
9															
10															
11															
12															
13															
14															
15	3 Res.														
16															
17															
18															
19															
20															
21															
22	4 Res.														
23															
24															
25															
26															
27															
28															
29	5 Res.														
30															
31															
32															
33															
34															
35															
36	6 Res.														
37															
38															
39															
40															
41															
42															

Demand Side Management
Projected Program Costs - System
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
			2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
		Phase VII Programs O&M	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
43	7 Non Res.	[redacted]													
44															
45															
46															
47															
48															
49															
50	8 Non Res.														
51															
52															
53															
54															
55															
56															
57	9 Non Res.														
58															
59															
60															
61															
62															
63															
64	10 Non Res.														
65															
66															
67															
68															
69															
70															
71	11 Non Res.														
72															
73															
74															
75															
76															
77															
78															
79		Total Phase VII Programs	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	28,581,058
80															
81															
82															
83															
84	Notes:														
85		1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
86		2 Data excludes Margin													
87		3 Data excludes Lost Revenues													
88															

Exhibit No.____

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Witness JEB
Schedule 46B
Statement 4

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
Row		2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1	[redacted]													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase II Programs	51,605	51,605	51,605	51,605	51,605	109,942	109,942	109,942	109,942	51,605	51,605	51,605	852,609
10														
11														
12														
13	Notes:													
14	1 Res. = Residential; Com. = Commercial													
15	2 Data excludes Margin													
16	3 Data excludes Lost Revenues													
17														

Demand Side Management

Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1–8	[redacted]													
9	Total Phase II Programs	58,244	58,244	58,244	58,244	58,244	124,085	124,085	124,085	124,085	58,244	58,244	58,244	962,290
10														
11														
12														
13	Notes:													
14	1 Res. = Residential; Com. = Commercial													
15	2 Data excludes Margin													
16	3 Data excludes Lost Revenues													
17														

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1	Phase III Programs O&M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2–21	[redacted]													
22														
23	Total Phase III Programs	21,667	21,667	21,667	21,667	21,667	21,667	21,667	21,667	21,667	21,667	21,667	21,667	260,000
24														
25														
26														
27	Notes:													
28	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
29	2 Data excludes Margin													
30	3 Data excludes Lost Revenues													

Demand Side Management
Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Exhibit No.____
Witness JEB
Schedule 46B
Statement 4
Page 4 of 14

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
Row		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1	Phase III Programs O&M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2	[redacted]													
3														
4														
5														
6														
7														
8														
9														
10														
11														
12														
13														
14														
15														
16														
17														
18														
19														
20														
21														
22														
23	Total Phase III Programs	-	-	-	-	-	-	-	-	-	-	-	-	-
24														
25														
26														
27	Notes:													
28	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
29	2 Data excludes Margin													
30	3 Data excludes Lost Revenues													

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1	Phase IV Programs O&M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2-7	[redacted]													
8														
9	Total Phase IV Programs	348,345	348,345	348,345	348,345	348,345	348,345	348,345	348,345	348,345	348,345	348,345	348,345	4,180,140
10														
11														
12	Notes:													
13	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
14	2 Data excludes Margin													
15	3 Data excludes Lost Revenues													
16														
17														
18														

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Statement 4
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Demand Side Management
Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1	[redacted]													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase IV Programs	368,281	368,281	368,281	368,281	368,281	368,281	368,281	368,281	368,281	368,281	368,281	368,281	4,419,374
10														
11														
12	Notes:													
13	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
14	2 Data excludes Margin													
15	3 Data excludes Lost Revenues													
16														
17														
18														

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Statement 4
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Demand Side Management

Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1	Phase V Programs O&M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2	[redacted]													
3														
4														
5														
6														
7														
8														
9	Total Phase V Programs	646,805	646,805	646,805	646,805	646,805	646,805	646,805	646,805	646,805	646,805	646,805	646,805	7,761,657
10														
11														
12	Notes:													
13	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
14	2 Data excludes Margin													
15	3 Data excludes Lost Revenues													
16														
17														
18														

Demand Side Management
Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1	[redacted]													
2														
3														
4														
5														
6														
7														
8														
9	Total Phase V Programs	737,128	737,128	737,128	737,128	737,128	737,128	737,128	737,128	737,128	737,128	737,128	737,128	8,845,540
10														
11														
12	Notes:													
13	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
14	2 Data excludes Margin													
15	3 Data excludes Lost Revenues													
16														
17														
18														

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1	Phase VI Programs O&M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2	[redacted]													
3														
4														
5														
6														
7														
8														
9														
10	Total Phase VI Programs	527,952	527,952	527,952	527,952	527,952	527,952	527,952	527,952	527,952	527,952	527,952	527,952	6,335,426
11														
12														
13	Notes:													
14	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
15	2 Data excludes Margin													
16	3 Data excludes Lost Revenues													
17														
18														
19														

-

Demand Side Management

Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information is Highlighted in Green

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Schedule 46B
Statement 4

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1	[redacted]													
2														
3														
4														
5														
6														
7														
8														
9														
10	Total Phase VI Programs	528,035	528,035	528,035	528,035	528,035	528,035	528,035	528,035	528,035	528,035	528,035	528,035	6,336,414
11														
12														
13	Notes:													
14	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
15	2 Data excludes Margin													
16	3 Data excludes Lost Revenues													
17														
18														
19														

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
			2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1		[redacted]												
2	1 Res.													
3														
4														
5														
6														
7														
8														
9	2 Res.													
10														
11														
12														
13														
14														
15														
16	3 Res.													
17														
18														
19														
20														
21														
22														
23	4 Res.													
24														
25														
26														
27														
28														
29														
30	5 Res.													
31														
32														
33														
34														
35														
36														
37	6 Res.													
38														
39														
40														
41														
42														
43														
44														
45	Notes:													
46		1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential												
47		2 Data excludes Margin												
48		3 Data excludes Lost Revenues												
49														

Demand Side Management
Projected Program Costs - System
Year: 2019
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
			2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
1		[redacted]												
2	1 Non Res.													
3														
4														
5														
6														
7														
8														
9	2 Non Res.													
10														
11														
12														
13														
14														
15														
16	3 Non Res.													
17														
18														
19														
20														
21														
22														
23	4 Non Res.													
24														
25														
26														
27														
28														
29														
30	5 Non Res.													
31														
32														
33														
34														
35														
36														
37														
38														
39														
40		Total Phase VII Programs	-	-	-	-	-	-	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241
41	Notes:													
42		1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential												
43		2 Data excludes Margin												
44		3 Data excludes Lost Revenues												
45														

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Witness JEB
Schedule 46B
Statement 4
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Column 13
2019
[redacted]

Column
13
2019
[redacted]
16,663,444

Demand Side Management
Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
			2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1		[redacted]												
2	1 Res.													
3														
4														
5														
6														
7														
8														
9	2 Res.													
10														
11														
12														
13														
14														
15														
16	3 Res.													
17														
18														
19														
20														
21														
22														
23	4 Res.													
24														
25														
26														
27														
28														
29														
30	5 Res.													
31														
32														
33														
34														
35														
36														
37	6 Res.													
38														
39														
40														
41														
42														
43														
44														
45	Notes:													
46	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
47	2 Data excludes Margin													
48	3 Data excludes Lost Revenues													
49														

Demand Side Management
Projected Program Costs - System
Year: 2020
Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Row			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
			2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
1		[redacted]												
2	1 Non Res.													
3														
4														
5														
6														
7														
8														
9	2 Non Res.													
10														
11														
12														
13														
14														
15														
16	3 Non Res.													
17														
18														
19														
20														
21														
22														
23	4 Non Res.													
24														
25														
26														
27														
28														
29														
30	5 Non Res.													
31														
32														
33														
34														
35														
36														
37														
38														
39														
40		Total Phase VII Programs	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269
41	Notes:													
42	1 Res. = Residential; Com. = Commercial; Non Res. = Non Residential													
43	2 Data excludes Margin													
44	3 Data excludes Lost Revenues													
45														

Exhibit No.____
Witness JEB
Schedule 46B
Statement 4

Column
13
2020
[redacted]

Column
13
2020
[redacted]
23,835,229

Demand Side Management
Projected Cost Summary
Common Costs
Rate Yr: July 1, 2019 to June 30, 2020
Dollars

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Witness JEB
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Statement 5
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Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
		Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	Common Costs System													
2	Energy Conservation Labor	[redacted]												
3	Customer Communication													
4	Consultant Support													
5	Dues & Associations	8,533	8,533	8,533	8,533	8,533	8,533	8,918	8,918	8,918	8,918	8,918	8,918	104,710
6	Energy Conservation Staff Support	3,333	3,333	3,333	3,333	3,333	3,333	3,400	3,400	3,400	3,400	3,400	3,400	40,400
7	Total	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 2,424,857
8														
9														
10														
11														
12														
13														
14	Notes:													
15	1 Data excludes Margin													

Demand Side Management

Projected Cost Summary

Common Costs

Year 2019

Dollars

Row		Column 1 2019 Jan	Column 2 2019 Feb	Column 3 2019 Mar	Column 4 2019 Apr	Column 5 2019 May	Column 6 2019 Jun	Column 7 2019 Jul	Column 8 2019 Aug	Column 9 2019 Sep	Column 10 2019 Oct	Column 11 2019 Nov	Column 12 2019 Dec
1	Common Costs System												
2	Energy Conservation Labor	[redacted]											
3	Customer Communication												
4	Consultant Support												
5	Dues & Associations	8,533	8,533	8,533	8,533	8,533	8,533	8,533	8,533	8,533	8,533	8,533	8,533
6	Energy Conservation Staff Support	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333
7	Total	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092	$ 199,092
8													
9													
10													
11													
12													
13													
14	Notes:												
15	1 Data excludes Margin												

Column
13
2019
Year
[redacted]
102,400
40,000
$ 2,389,110

Demand Side Management

Projected Cost Summary
Common Costs
Year 2020
Dollars

Row		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Common Costs												
2	Energy Conservation Labor	[redacted]											
3	Customer Communication												
4	Consultant Support												
5	Dues & Associations	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
6	Energy Conservation Staff Support	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
7	Total	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050	$ 205,050
8													
9													
10													
11													
12													
13													
14	Notes:												
15	1 Data excludes Margin												

Column 13
2020
Year
[redacted]
$ 107,020
$ 40,800
$ 2,460,605

Demand Side Management
DSM Phase VII Residential Appliance Recycling Program Projected Cost Limits
<u>Virginia Jurisdictional</u>
Years as Shown
In Dollars

Exhibit No.____
Witness JEB
Schedule 46B
Statement 7
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Row					Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1										
2	A.	System Program Costs								
3		Res	Appliance Recycling	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 8,396,031
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Res	Appliance Recycling	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Res	Appliance Recycling	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,955,519
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Res	Appliance Recycling	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 731,908
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Res	Appliance Recycling	Rev $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 4,944,287
19			Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	67,190	498,353	957,536	1,416,718	1,875,901	4,815,698
22										
23	F.	Total Cost Limit for Program		$	$ 1,281,183	$ 2,494,909	$ 2,940,034	$ 3,400,428	$ 3,860,903	$ 13,977,458
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,955,519
25			Virginia Jurisdiction Program Margin	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 731,908
26			Virginia Jurisdictional Common Costs	O&M $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 474,333
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 67,190	$ 498,353	$ 957,536	$ 1,416,718	$ 1,875,901	$ 4,815,698
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 1,345,242**	**$ 2,619,655**	**$ 3,087,036**	**$ 3,570,450**	**$ 4,053,948**	**$ 14,676,331**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							
34										
35										
36										
37										
38										

Demand Side Management
DSM Phase VII Residential Customer Engagement Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

Exhibit No.____
Witness JEB
Schedule 46B
Statement 7
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Row		Description		Unit	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1										
2	A.	System Program Costs								
3		Res	Customer Engagement	O&M $	[redacted]					$ 2,098,205
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Res	Customer Engagement	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Res	Customer Engagement	O&M $	[redacted]					$ 2,006,501
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Res	Customer Engagement	O&M $	[redacted]					$ 184,598
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Res	Customer Engagement	Rev $	[redacted]					$ 27,699,474
19			Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	576,964	3,345,412	5,373,747	7,618,949	10,064,007	26,979,080
22										
23	F.	Total Cost Limit for Program		$	$ 1,233,166	$ 3,768,660	$ 5,782,937	$ 8,029,350	$ 10,475,700	$ 29,289,813
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 2,006,501
25			Virginia Jurisdiction Program Margin	O&M $						$ 184,598
26			Virginia Jurisdictional Common Costs	O&M $						$ 119,634
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 576,964	$ 3,345,412	$ 5,373,747	$ 7,618,949	$ 10,064,007	$ 26,979,080
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 1,294,824**	**$ 3,957,093**	**$ 6,072,084**	**$ 8,430,818**	**$ 10,999,485**	**$ 30,754,304**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							

Demand Side Management
DSM Phase VII Residential Efficient Products Marketplace Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

Row					Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total	
1											
2	A.	System Program Costs			[redacted]						
3		Res	Efficient Products Marketplace	O&M $						$ 36,407,866	
4											
4										-	
5			Total Program Costs	O&M $	$ 6,606,980	$ 6,752,607	$ 7,270,634	$ 7,672,306	$ 8,105,339	$ 36,407,866	
6											
7	B.	Virginia Jurisdictional Program Assignment Percentages									
8		Res	Efficient Products Marketplace	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%		
9											
9											
10											
11	C.	Virginia Jurisdictional Program Costs			[redacted]						
12		Res	Efficient Products Marketplace	O&M $						$ 34,619,813	
13											
13											
14			Total Va. Juris Program Costs	O&M $	$ 6,606,980	$ 6,347,450	$ 6,834,396	$ 7,211,968	$ 7,619,019	$ 34,619,813	
15											
13											
14	D.	Virginia Jurisdictional Margin on Program Costs			[redacted]						
15		Res	Efficient Products Marketplace	O&M $						$ 3,185,023	
16											
16											
17			Total Va. Juris Margin on Program Costs	O&M $	$ 607,842	$ 583,965	$ 628,764	$ 663,501	$ 700,950	$ 3,185,023	
16											
17	E.	Virginia Jurisdiction Lost Revenues			[redacted]						
18		Res	Efficient Products Marketplace	Rev $						$ 43,591,391	
19											
19		0	0	Rev $						$ 728,831	
20			Residential Base Rate	per KWh	$ 0.05643	$ 0.05643	$ 0.05643	$ 0.05643	$ 0.05643	$ 0.05643	
19			Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533		
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%		
21			Total Net Lost Revenue Dollars	Rev $	1,331,394	2,290,912	7,232,323	12,775,480	18,827,580	42,457,688	
22											
23	F.	Total Cost Limit for Program		$	$ 8,940,145	$ 9,600,783	$ 15,102,972	$ 21,080,950	$ 27,601,819	$ 82,326,668	
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 34,619,813	
25			Virginia Jurisdiction Program Margin	O&M $						$ 3,185,023	
26			Virginia Jurisdictional Common Costs	O&M $						$ 2,064,144	
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 1,331,394	$ 2,290,912	$ 7,232,323	$ 12,775,480	$ 18,827,580	$ 42,457,688	52%
28											
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 9,387,152**	**$ 10,080,822**	**$ 15,858,120**	**$ 22,134,997**	**$ 28,981,910**	**$ 86,443,001**	
30											
31		Notes:									
32			1 OSS = Off System Sales; VOM = Variable O&M.								
33			2 No margin allowed for Demand Response Programs.								
34											
35											
36											
37											
38											

Demand Side Management
DSM Phase VII Residential Home Energy Assessment Program Projected Cost Limits
<u>Virginia Jurisdictional</u>
Years as Shown
In Dollars

Row				Year 1	Year 2	Year 3	Year 4	Year 5	
1				2019	2020	2021	2022	2023	Total
2	A.	System Program Costs							
3		Res Home Energy Assessment	O&M $	[redacted]					$ 21,492,927
6									
7	B.	Virginia Jurisdictional Program Assignment Percentages							
8		Res Home Energy Assessment	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10									
11	C.	Virginia Jurisdictional Program Costs							
12		Res Home Energy Assessment	O&M $	[redacted]					$ 20,337,783
13									
14	D.	Virginia Jurisdictional Margin on Program Costs							
15		Res Home Energy Assessment	O&M $	[redacted]					$ 1,871,076
16									
17	E.	Virginia Jurisdiction Lost Revenues							
18		Res Home Energy Assessment	Rev $	[redacted]					$ 4,330,554
19		Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	
20		Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21		Total Net Lost Revenue Dollars	Rev $	71,317	258,509	807,129	1,322,216	1,758,756	4,217,927
22									
23	F.	Total Cost Limit for Program	$	$ 2,651,564	$ 4,906,916	$ 6,088,800	$ 6,723,963	$ 7,268,147	$ 27,639,390
24		Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 20,337,783
25		Virginia Jurisdiction Program Margin	O&M $						$ 1,871,076
26		Virginia Jurisdictional Common Costs	O&M $						$ 1,212,604
27		Virginia Jurisdictional Lost Revenues	Rev $	$ 71,317	$ 258,509	$ 807,129	$ 1,322,216	$ 1,758,756	$ 4,217,927
28									
29		**Cost Limit with a 5% variance allowance**	**$**	**$ 2,784,142**	**$ 5,152,261**	**$ 6,393,240**	**$ 7,060,161**	**$ 7,631,555**	**$ 29,021,359**
30									

31 Notes:
32 1 OSS = Off System Sales; VOM = Variable O&M.
33 2 No margin allowed for Demand Response Programs.
34
35
36
37
38

Demand Side Management
DSM Phase VII Residential Smart Thermostat - DR Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

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Row				Unit	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1										
2	A.	System Program Costs								
3		Res	Smart Thermostat - DR	O&M $	[redacted]					$ 10,615,728
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Res	Smart Thermostat - DR	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Res	Smart Thermostat - DR	O&M $	[redacted]					$ 10,030,553
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Res	Smart Thermostat - DR	O&M $	[redacted]					$ -
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Res	Smart Thermostat - DR	Rev $	[redacted]					$ -
19			Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	-	-	-	-	-	-
22										
23	F.	Total Cost Limit for Program		$	[redacted]					$ 10,532,080
24			Virginia Jurisdiction Program O&M Costs	O&M $						$ 10,030,553
25			Virginia Jurisdiction Program Margin	O&M $						$ -
26			Virginia Jurisdictional Common Costs	O&M $						$ 501,528
27			Virginia Jurisdictional Lost Revenues	Rev $	$ -	$ -	$ -	$ -	$ -	$ -
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 951,236**	**$ 1,793,037**	**$ 2,316,104**	**$ 2,832,238**	**$ 3,166,070**	**$ 11,058,684**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							
34										
35										
36										
37										
38										

Demand Side Management
DSM Phase VII Residential Smart Thermostat - EE Program Projected Cost Limits
<u>Virginia Jurisdictional</u>
Years as Shown
In Dollars

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Row				Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1									
2	A.	System Program Costs							
3		Res Smart Thermostat - EE	O&M $	[redacted]					$ 6,425,753
6									
7	B.	Virginia Jurisdictional Program Assignment Percentages							
8		Res Smart Thermostat - EE	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10									
11	C.	Virginia Jurisdictional Program Costs							
12		Res Smart Thermostat - EE	O&M $	[redacted]					$ 6,083,893
13									
14	D.	Virginia Jurisdictional Margin on Program Costs							
15		Res Smart Thermostat - EE	O&M $	[redacted]					$ 559,718
16									
17	E.	Virginia Jurisdiction Lost Revenues							
18		Res Smart Thermostat - EE	Rev $	[redacted]					$ 4,470,603
19		Residential Base Rate	per KWh	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	$ 0.05533	
20		Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21		Total Net Lost Revenue Dollars	Rev $	37,726	332,245	754,398	1,292,111	1,937,855	4,354,334
22									
23	F.	Total Cost Limit for Program	$	$ 876,204	$ 1,541,302	$ 2,159,359	$ 2,936,436	$ 3,847,385	$ 11,360,686
24		Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 6,083,893
25		Virginia Jurisdiction Program Margin	O&M $						$ 559,718
26		Virginia Jurisdictional Common Costs	O&M $						$ 362,741
27		Virginia Jurisdictional Lost Revenues	Rev $	$ 37,726	$ 332,245	$ 754,398	$ 1,292,111	$ 1,937,855	$ 4,354,334
28									
29		**Cost Limit with a 5% variance allowance**	**$**	**$ 920,015**	**$ 1,618,367**	**$ 2,267,327**	**$ 3,083,258**	**$ 4,039,754**	**$ 11,928,721**
30									
31		Notes:							
32		1 OSS = Off System Sales; VOM = Variable O&M.							
33		2 No margin allowed for Demand Response Programs.							
34									
35									
36									
37									
38									

Demand Side Management
DSM Phase VII Non Res. Lighting Systems & Controls Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

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Row					Year 1	Year 2	Year 3	Year 4	Year 5	
1					2019	2020	2021	2022	2023	Total
2	A.	System Program Costs								
3		Non Res.	Lighting Systems & Controls	O&M $	[redacted]					$ 11,236,728
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Non Res.	Lighting Systems & Controls	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Non Res.	Lighting Systems & Controls	O&M $	[redacted]					$ 10,656,929
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Non Res.	Lighting Systems & Controls	O&M $	[redacted]					$ 980,437
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Non Res.	Lighting Systems & Controls	Rev $	[redacted]					$ 4,498,819
19			Non Residential Base Rate	per KWh	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	103,944	357,873	912,720	1,306,666	1,700,613	4,381,816
22										
23	F.	Total Cost Limit for Program		$	$ 1,915,909	$ 3,530,215	$ 3,347,965	$ 3,743,334	$ 4,117,159	$ 16,654,582
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 10,656,929
25			Virginia Jurisdiction Program Margin	O&M $						$ 980,437
26			Virginia Jurisdictional Common Costs	O&M $						$ 635,400
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 103,944	$ 357,873	$ 912,720	$ 1,306,666	$ 1,700,613	$ 4,381,816
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 2,011,704**	**$ 3,706,726**	**$ 3,515,363**	**$ 3,930,501**	**$ 4,323,017**	**$ 17,487,311**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							
34										
35										
36										
37										
38										

Demand Side Management
DSM Phase VII Non Res. HVAC Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

Row				Unit	Year 1	Year 2	Year 3	Year 4	Year 5	
1					2019	2020	2021	2022	2023	Total
2	A.	System Program Costs								
3		Non Res.	Heating & Cooling Efficiency	O&M $	[redacted]					$ 8,804,934
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Non Res.	Heating & Cooling Efficiency	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Non Res.	Heating & Cooling Efficiency	O&M $	[redacted]					$ 8,341,975
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Non Res.	Heating & Cooling Efficiency	O&M $	[redacted]					$ 767,462
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Non Res.	Heating & Cooling Efficiency	Rev $	[redacted]					$ 5,098,042
19			Non Residential Base Rate	per KWh	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	64,353	499,377	983,309	1,467,242	1,951,174	4,965,454
22										
23	F.	Total Cost Limit for Program		$	$ 1,318,407	$ 2,597,667	$ 3,062,484	$ 3,559,397	$ 4,034,312	$ 14,572,266
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 8,341,975
25			Virginia Jurisdiction Program Margin	O&M $						$ 767,462
26			Virginia Jurisdictional Common Costs	O&M $						$ 497,375
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 64,353	$ 499,377	$ 983,309	$ 1,467,242	$ 1,951,174	$ 4,965,454
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 1,384,327**	**$ 2,727,550**	**$ 3,215,608**	**$ 3,737,367**	**$ 4,236,028**	**$ 15,300,879**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							
34										
35										
36										
37										
38										

Demand Side Management
DSM Phase VII Non Res. Window Film Program Projected Cost Limits
<u>Virginia Jurisdictional</u>
Years as Shown
In Dollars

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Row				Year 1	Year 2	Year 3	Year 4	Year 5	
1				2019	2020	2021	2022	2023	Total
2	A.	System Program Costs							
3		Non Res. Window Film	O&M $	[redacted]					$ 2,085,953
6									
7	B.	Virginia Jurisdictional Program Assignment Percentages							
8		Non Res. Window Film	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10									
11	C.	Virginia Jurisdictional Program Costs							
12		Non Res. Window Film	O&M $	[redacted]					$ 1,979,146
13									
14	D.	Virginia Jurisdictional Margin on Program Costs							
15		Non Res. Window Film	O&M $	[redacted]					$ 182,081
16									
17	E.	Virginia Jurisdiction Lost Revenues							
18		Non Res. Window Film	Rev $	[redacted]					$ 912,838
19		Non Residential Base Rate	per KWh	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	
20		Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21		Total Net Lost Revenue Dollars	Rev $	11,716	89,985	176,225	262,466	348,706	889,098
22									
23	F.	Total Cost Limit for Program	$	$ 363,922	$ 576,163	$ 660,350	$ 750,118	$ 817,775	$ 3,168,328
24		Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 1,979,146
25		Virginia Jurisdiction Program Margin	O&M $						$ 182,081
26		Virginia Jurisdictional Common Costs	O&M $						$ 118,003
27		Virginia Jurisdictional Lost Revenues	Rev $	$ 11,716	$ 89,985	$ 176,225	$ 262,466	$ 348,706	$ 889,098
28									
29		**Cost Limit with a 5% variance allowance**	**$**	**$ 382,118**	**$ 604,971**	**$ 693,367**	**$ 787,624**	**$ 858,664**	**$ 3,326,744**
30									
31		Notes:							
32		1 OSS = Off System Sales; VOM = Variable O&M.							
33		2 No margin allowed for Demand Response Programs.							
34									
35									
36									
37									
38									

Demand Side Management
DSM Phase VII Non Res. Small Manufacturing Program Projected Cost Limits
Virginia Jurisdictional
Years as Shown
In Dollars

Row				Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1									
2	A.	System Program Costs							
3		Non Res. Small Manufacturing	O&M $	[redacted]					$ 5,902,427
6									
7	B.	Virginia Jurisdictional Program Assignment Percentages							
8		Non Res. Small Manufacturing	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10									
11	C.	Virginia Jurisdictional Program Costs							
12		Non Res. Small Manufacturing	O&M $	[redacted]					$ 5,598,141
13									
14	D.	Virginia Jurisdictional Margin on Program Costs							
15		Non Res. Small Manufacturing	O&M $	[redacted]					$ 515,029
16									
17	E.	Virginia Jurisdiction Lost Revenues							
18		Non Res. Small Manufacturing	Rev $	[redacted]					$ 1,465,710
19		Non Residential Base Rate	per KWh	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	
20		Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21		Total Net Lost Revenue Dollars	Rev $	18,458	143,445	282,670	421,896	561,122	1,427,591
22									
23	F.	Total Cost Limit for Program	$	$ 975,457	$ 1,483,119	$ 1,654,997	$ 1,787,096	$ 1,973,871	$ 7,874,540
24		Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 5,598,141
25		Virginia Jurisdiction Program Margin	O&M $	[redacted]					$ 515,029
26		Virginia Jurisdictional Common Costs	O&M $	[redacted]					$ 333,779
27		Virginia Jurisdictional Lost Revenues	Rev $	$ 18,458	$ 143,445	$ 282,670	$ 421,896	$ 561,122	$ 1,427,591
28									
29		**Cost Limit with a 5% variance allowance**	**$**	**$ 1,024,230**	**$ 1,557,275**	**$ 1,737,747**	**$ 1,876,451**	**$ 2,072,565**	**$ 8,268,267**
30									
31		Notes:							
32		1 OSS = Off System Sales; VOM = Variable O&M.							
33		2 No margin allowed for Demand Response Programs.							
34									
35									
36									
37									
38									

Demand Side Management
DSM Phase VII Non Res. Office Program Projected Cost Limits
<u>Virginia Jurisdictional</u>
Years as Shown
In Dollars

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Row				Unit	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Total
1										
2	A.	System Program Costs								
3		Non Res.	Office	O&M $	[redacted]					$ 5,521,544
6										
7	B.	Virginia Jurisdictional Program Assignment Percentages								
8		Non Res.	Office	O&M $	100.0%	94.0%	94.0%	94.0%	94.0%	
10										
11	C.	Virginia Jurisdictional Program Costs								
12		Non Res.	Office	O&M $	[redacted]					$ 5,238,366
13										
14	D.	Virginia Jurisdictional Margin on Program Costs								
15		Non Res.	Office	O&M $	[redacted]					$ 481,930
16										
17	E.	Virginia Jurisdiction Lost Revenues								
18		Non Res.	Office	Rev $	[redacted]					$ 2,462,573
19			Non Residential Base Rate	per KWh	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	$ 0.04490	
20			Reduction % for OSS and VOM	%	2.6%	2.6%	2.6%	2.6%	2.6%	
21			Total Net Lost Revenue Dollars	Rev $	31,073	241,184	474,971	708,757	942,543	2,398,528
22										
23	F.	Total Cost Limit for Program		$	$ 954,569	$ 1,486,885	$ 1,742,764	$ 1,987,026	$ 2,259,908	$ 8,431,151
24			Virginia Jurisdiction Program O&M Costs	O&M $	[redacted]					$ 5,238,366
25			Virginia Jurisdiction Program Margin	O&M $						$ 481,930
26			Virginia Jurisdictional Common Costs	O&M $						$ 312,328
27			Virginia Jurisdictional Lost Revenues	Rev $	$ 31,073	$ 241,184	$ 474,971	$ 708,757	$ 942,543	$ 2,398,528
28										
29		**Cost Limit with a 5% variance allowance**		**$**	**$ 1,002,297**	**$ 1,561,229**	**$ 1,829,902**	**$ 2,086,377**	**$ 2,372,903**	**$ 8,852,709**
30										
31		Notes:								
32			1 OSS = Off System Sales; VOM = Variable O&M.							
33			2 No margin allowed for Demand Response Programs.							
34										
35										
36										
37										
38										

9.2% ROE
5.0% Common Costs to Direct Cost Ratio

Demand Side Management
2017 Actual DSM Expenses - System
O&M in Dollars

Extraordinary Sensitive Information
is Highlighted in Green

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Row			Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Year 2017
1															
2	Program Wave	Total Program Costs - System													
3	DSM II	[redacted]													
4	DSM II														
5	DSM II														
6	DSM II														
7	DSM II														
8	DSM II														
9	DSM II														
10															
11	Pilot														
12		Total DSM II Programs & Pilot	2,237,929	1,102,666	562,183	518,435	161,372	53,878	130,783	190,804	96,416	81,766	96,271	172,767	5,405,269
13															
14	Program Wave	Total Program Costs - System													
15	DSM III	[redacted]													
16	DSM III														
17	DSM III														
18		Total DSM-III Programs	839,505	698,882	1,135,490	840,651	1,368,232	644,586	797,136	829,436	1,174,149	1,010,686	1,234,045	604,274	11,177,072
19															
20	Program Wave	Total Program Costs - System													
21	DSM IV	[redacted]													
22	DSM IV														
23		Total DSM-IV Programs	749,378	370,545	873,534	583,507	590,094	389,233	382,571	414,252	80,822	576,440	623,921	503,498	6,137,793
24															
25	Program Wave	Total Program Costs - System													
26	DSM V	[redacted]													
27	DSM V														
28		Total DSM-V Programs	255,219	168,387	312,415	417,615	465,792	323,752	649,044	329,638	379,274	457,957	330,681	416,503	4,506,276
29															
30	Program Wave	Total Program Costs - System													
31	DSM VI	[redacted]													
32															
33		Common Costs - System	97,652	189,486	(11,420)	85,809	85,807	167,850	118,163	138,850	136,213	195,155	138,874	40,314	1,382,752
34															
35		Virginia Assignment %s for A5 Purposes													
36	DSM II	Com Distributed Generation	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
37	DSM II	Commercial Audit	79.1924%	29.5310%	41.3746%	97.0857%	100.0000%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	74.9835%	
38	DSM II	Commercial Duct Testing & Sealing	93.5129%	98.7500%	29.3722%	96.0854%	100.0000%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	81.4133%	
39	DSM II	Residential Audit	99.4036%	95.7252%	85.9660%	96.3263%	100.4303%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	82.8531%	
40	DSM II	Residential Duct Testing & Sealing	91.5308%	98.5859%	95.5278%	94.6040%	100.1568%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	74.8372%	
41	DSM II	Residential Heat Pump Tune Up	96.3401%	91.7075%	83.3311%	93.5224%	99.1726%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	74.3397%	
42	DSM II	Residential Heat Pump Upgrade	91.9997%	89.2475%	92.2591%	95.7562%	101.7575%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	58.2796%	
43															
44	DSM II	Electric Vehicles	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
45															
46															
47	DSM III	Commercial Lighting Systems & Controls	97.9368%	96.9748%	98.3858%	94.9999%	92.2369%	98.8827%	99.2930%	97.0415%	93.9128%	99.1833%	99.4012%	88.1917%	
48	DSM III	Commercial HVAC	95.9589%	98.0955%	92.4833%	98.1500%	95.8962%	93.6160%	99.5511%	92.6935%	98.2348%	97.5502%	98.2524%	92.1014%	
49	DSM III	Commercial Solar Window Film	94.4062%	95.2222%	94.5537%	96.7454%	95.8807%	90.6378%	98.4144%	99.1469%	97.1029%	97.9111%	98.0851%	83.8929%	
50															
51															
52	DSM IV	Residential Appliance Recycling	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
53	DSM IV	Residential Income and Age Qualifying Home Improvement	83.4480%	89.2902%	94.9973%	93.0076%	96.5372%	95.2476%	97.1752%	96.8264%	85.4237%	99.2069%	97.9303%	90.1474%	
54															
55	DSM V	Commercial Small Bus Improvement	97.8586%	96.9323%	98.3829%	98.9386%	99.0551%	97.7305%	98.6976%	98.0345%	98.4490%	98.2616%	98.3085%	86.9082%	
56	DSM V	Residential LED	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	
57															
58	DSM VI	Commercial Prescriptive	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
59															
60		Common Costs	82.9287%	82.9287%	82.9287%	82.9287%	82.9287%	82.9287%	69.6614%	69.6614%	69.6614%	69.6614%	69.6614%	69.6614%	
61															
62		Common Costs - A5	80,981	157,138	(9,471)	71,161	71,159	139,196	82,314	96,725	94,888	135,947	96,742	28,084	1,044,863
63		Program Costs - A5	3,826,963	2,209,770	2,643,754	2,258,118	2,476,053	1,353,330	1,779,219	1,795,718	1,738,508	2,157,289	2,325,992	1,521,946	26,086,660
64		Program & Common Costs - A5	3,907,944	2,366,908	2,634,283	2,329,278	2,547,212	1,492,525	1,861,532	1,892,443	1,833,396	2,293,237	2,422,733	1,550,030	27,131,523
65															
66	Notes:														
67		1 Res. = Residential; Com. = Commercial													
68		2 Data excludes Margin													
69		3 Data excludes Lost Revenues													
70															
71															

Demand Side Management
2017 Actual DSM Expenses - System
O&M in Dollars

Extraordinary Sensitive Information
is Highlighted in Green

Exhibit No.____
Witness JEB
Schedule 46B
Statement 8

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Year 2017
Program System	[redacted]												
Grand Total without Electric Vehicles	4,129,822	2,556,895	3,067,914	2,614,093	2,798,122	2,606,916	3,178,644	3,109,544	2,984,727	2,456,383	2,568,793	1,810,116	33,881,968

	Jan - Jun	Jul-Dec
Total A5 Costs	14,739,551	11,221,195
Total Program Costs exclude EV	17,773,762	16,108,207
	82.929%	69.661%

Demand Side Management
Projected Cost Summary - System
Approved DSM Program O&M Costs
Rate Yr: July 1, 2019 to June 30, 2020

Extraordinary Sensitive Information
is Highlighted in Green

Row	Dollars	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13
		2019	2019	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	Rate
	Programs	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Year
1	DSM I Total O&M (part of Base Rates)	1,230,039	1,230,039	1,230,039	322,510	322,510	322,510	325,824	325,824	325,824	325,824	325,824	1,242,678	7,529,447
2														
3	DSM II Total O&M excl Pilot	109,942	109,942	109,942	51,605	51,605	51,605	58,244	58,244	58,244	58,244	58,244	124,085	899,945
4														
5	DSM III Total O&M	21,667	21,667	21,667	21,667	21,667	21,667	-	-	-	-	-	-	130,000
6														
7	DSM IV Total O&M	348,345	348,345	348,345	348,345	348,345	348,345	368,281	368,281	368,281	368,281	368,281	368,281	4,299,757
8														
9	DSM V Total O&M	646,805	646,805	646,805	646,805	646,805	646,805	737,128	737,128	737,128	737,128	737,128	737,128	8,303,598
10														
11	DSM VI Total O&M	527,952	527,952	527,952	527,952	527,952	527,952	528,035	528,035	528,035	528,035	528,035	528,035	6,335,920
12														
13	DSM VII Total O&M	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241	2,777,241	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	1,986,269	28,581,058
14														
13	Total DSM Program O&M	5,661,990	5,661,990	5,661,990	4,696,125	4,696,125	4,696,125	4,003,781	4,003,781	4,003,781	4,003,781	4,003,781	4,986,475	56,079,726
14														
15														
16														
17	Notes:													
18	1 System = Total of All Jurisdictions													
19	2 Data excludes Margin													
20	3 Data excludes Lost Revenues													
21	4 Data excludes Amortizations													
22														

EXHIBIT TW/EM – 4

RESPONSE TO SIERRA CLUB 3-1

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 1 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 1

Please provide a table that includes the program costs for all the programs implemented over the next ten years, including programs from Phases I through VII. Please break out the budgets/costs by phases and by programs. Provide the response in working electronic Excel format, with any formulas intact.

Response:

See the Company's response to Staff Set 1-2 for the requested information.

EXHIBIT TW/EM – 5

RESPONSE TO SIERRA CLUB 4-13, ATTACHMENT

PUBLIC VERSION

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 13 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Lisa R. Crabtree /for
Jarvis E. Bates
Energy Conservation Compliance Consultant
Dominion Energy Virginia

Question No. 13

Refer to Bates' Testimony, at page 9. Please provide a table, that sums to the $262 million budget, with the following details:

a. Costs by year for calendar years 2018 through 2023,
b. Costs broken down by (1) program costs, (2) common costs, (3) margin, and (4) lost revenue, and
c. Costs broken down by active programs across all phases, with the phases identified as part of the response.

Response:

See Extraordinarily Sensitive Attachment Sierra Club Set 4-13, which provides a summary for existing programs as well as the proposed energy efficiency programs. Also see the Company's response to Staff Set 1-2 and specifically Extraordinarily Sensitive Attachment Staff Set 1-2 (JEB), Statement 7, which provides by program the annual breakdown.

Extraordinarily Sensitive Attachment Sierra Club Set 4-13 contains extraordinarily sensitive DSM Contracts and Prices information, as noted by green shading, and is subject to the conditions in 5 VAC 5-20-170, the Company's Motion for Entry of a Protective Ruling and Additional Protective Treatment filed on October 3, 2018 in Case No. PUR-2018-00168, and the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information issued on October 23, 2018 in Case No. PUR-2018-00168.

Dominion Energy - Virginia

Extraordinarily Sensitive

Energy Efficiency Programs Potential Spend / Proposed Spend

($Millions)

	Projected Rate Year Spend ('18 -'19) [1]					Projected Rate Year Spend ('19 -'20) [2]					Five Year Cost Cap Total [3]				
Programs	Program Costs	Margin	Common Costs	Lost Revenue	Total	Program Costs	Margin	Common Costs	Lost Revenue	Total	Program Costs	Margin	Common Costs	Lost Revenue	Total
Phase III															
Commercial Lighting Systems & Controls	[redacted]			$0.0	$3.7	[redacted]			$0.0	$0.1					
Commercial HVAC				$0.0	$1.2				$0.0	$0.1					
Commercial Solar Window Film				$0.0	$1.3				$0.0	$0.0					
Phase IV															
Residential Income Qualifying Audit	[redacted]			$0.0	$5.0	[redacted]			$0.0	$4.6					
Phase V															
Non Residential Small Bus Improvement	[redacted]			$0.0	$7.8	[redacted]			$0.0	$8.9					
Phase VI															
Non Residential Prescriptive	[redacted]			$0.0	$6.9	[redacted]			$0.0	$6.8					
Phase VII															
Residential Appliance Recycling											[redacted]			$4.8	$14.0
Residential Customer Engagement														$27.0	$29.3
Residential Efficient Products Marketplace														$42.5	$82.3
Residential Home Energy Assessment														$4.2	$27.6
Residential Smart Thermostat - EE														$4.4	$11.4
Non Residential Lighting Systems & Controls														$4.4	$16.7
Non Residential Heating & Cooling Efficiency														$5.0	$14.6
Non Residential Window Film														$0.9	$3.2
Non Residential Small Manufacturing														$1.4	$7.9
Non Residential Office														$2.4	$8.4
Subtotal					**$25.9**					**$20.4**					**$215.3**
Total															**$262**

Footnotes:

1 - For Phases III - VI, represents projected rate year costs (Jul '18 - Jun '19) in revenue requirement approved in case PUR-2017-00129. Includes program costs, common costs, and margin.

2 - For Phases III - VI, represents projected rate year costs (Jul '19 - Jun '20) in revenue requirement proposed in case PUR-2018-00168. Includes program costs, common costs, and margin.

3 - For Phase VII, represents proposed 5 yr. cost caps for 10 EE programs in case PUR-2018-00168 . Includes estimates for program costs, common costs, margin, and lost revenue.

EXHIBIT TW/EM – 6

RESPONSE TO SIERRA CLUB 2-6

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 6 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 6 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 6 (a-d, f-h)

For each of the programs included in the Company's DSM Plan, please provide the following information, for each program year:

(a) first-year energy savings (MW-hr);
(b) lifetime energy savings (MW-hr);
(c) peak capacity savings (kW), broken out by seasons where available;
(d) average measure life (years);
(f) number of customers participating in the program;
(g) cumulative energy savings (MW-hr) adjusted for decay, for each year over the lifetime of the program; and
(h) cumulative peak capacity savings (kW) adjusted for decay, for each year over the lifetime of the measures.

Response:

(a) The Company objects to this request on the basis that it would require original work.

(b) See Confidential Attachment Staff Set 1-11(1) (DRK) for the lifetime energy savings associated with the proposed Phase VII programs.

(c) See Confidential Attachment Staff Set 1-11(1) (DRK) for the peak capacity savings associated with the proposed Phase VII programs. The peak occurs in July.

(d) See Schedule 11 to the direct testimony of Company Witness Deanna R. Kesler for the measure lives associated with the proposed Phase VII programs.

(f) See Extraordinarily Sensitive Attachment Staff Set 1-2 (1) (DRK) for the number of customers projected to participate in the proposed Phase VII programs.

(g) See Confidential Attachment Staff Set 1-11 (1) (DRK) for the cumulative energy savings for the proposed Phase VII programs.

(h) See Confidential Attachment Staff Set 1-11 (1) (DRK) for the cumulative peak capacity savings for the proposed Phase VII programs.

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 6 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No. 6 (e)

For each of the programs included in the Company's DSM Plan, please provide the following information, for each program year:

(e) number of customers eligible for the program;

Response:

(e) As of December 2018, the table below illustrates the approximate number of customers eligible within the Company's Virginia Service territory for each of the proposed Phase VII programs:

Proposed DSM Phase VII Program	Eligible Customer Count
Non-residential Heating and Cooling Efficiency Program	225,486
Non-residential Lighting Systems & Controls Program	225,486
Non-residential Window Film Program	225,486
Non-residential Office Program	225,486
Non-residential Small Manufacturing Program	225,486
Residential Appliance Recycling Program	2,232,756
Residential Home Energy Assessment Program	2,232,756
Residential Smart Thermostat Management Program (DR)	2,232,333
Residential Smart Thermostat Management Program (EE)	2,232,756
Residential Efficient Products Marketplace Program	2,232,756
Residential Customer Engagement Program	2,232,756

EXHIBIT TW/EM – 7

RESPONSE TO SIERRA CLUB 2-14

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 14 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Debra A. Stephens
Regulatory Specialist
Virginia Electric and Power Company

The following response to Question No. 14 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 14

Please provide the following historic information for each of the past five years, by customer class:

(a) Number of customers;
(b) Retail electricity sales;
(c) Revenues collected; and
(d) Rates, including energy charges, demand charges, customer charges, DSM charges, and any other charges included in customer rates.

Response:

The Company objects to this request as overly broad, unduly burdensome and not relevant or reasonably calculated to lead to the production of admissible evidence to the extent it seeks historic information for the past five years. The Company further objects to this request becaue it would require original work. Subject to and notwithstanding these objections, the Company provides the following response.

(a) There was a methodology change ordered by the Commission in the 2016 VA DSM case, which required the Company to remove Federal Non MS customers from the Virginia Jurisdictional case. These customers have been manually removed from the historical data since 2016. The adjusted historical information by customer class for 2016, 2017 and 2018 has been provided in Attachment Sierra Club Set 2-14. Virginia Jurisdictional information prior to 2016 included Federal Non MS customers therefore has not been provided in this response.

(b) There was a methodology change ordered by the Commission in the 2016 VA DSM case, which required the Company to remove Federal Non MS customers from the Virginia Jurisdictional case. These customers' sales have been manually removed from the historical data since 2016. The adjusted historical information by customer class for 2016, 2017 and 2018 has been provided in Attachment Sierra Club Set 2-14. Virginia Jurisdictional information prior to 2016 included Federal Non MS sales therefore has not been provided in this response.

(c) There was a methodology change ordered by the Commission in the 2016 VA DSM case which required the Company to remove Federal Non MS customers from the Virginia Jurisdictional case. The Company's Virginia Jurisdictional revenues have not been adjusted to remove the non-MS revenues from these booked revenues since they are not used in the rate design methodology. Therefore these adjusted revenues are not available for the historical period.

(d) The Company's current rate schedules are available on the Dominion Energy website at www.doninionenergy.com. These rate schedules provide all components of each rate including the energy charges, demand charges, customer charges, and DSM charges.

EXHIBIT TW/EM – 8

RESPONSE TO SIERRA CLUB 2-15

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 15 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Debra A. Stephens
Regulatory Specialist
Virginia Electric and Power Company

The following response to Question No. 15 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 15

Please provide any and all forecasts that the Company has of the following information for the next five years, by customer class:

(a) Number of customers;
(b) Retail electricity sales;
(c) Revenues collected; and
(d) Rates, including energy charges, demand charges, customer charges, DSM charges, and any other charges included in customer rates.

Response:

The Company objects to this request as overly broad, unduly burdensome and not relevant or reasonably calculated to lead to the production of admissible evidence to the extent it seeks "any and all forecasts" without limitation. The Company further objects to this request because it would require original work. Subject to and notwithstanding these objections, the Company provides the following response.

(a) The Company's customer forecasts are available in its annual Integrated Resource Plan filings and Updates, the most recent of which was filed in Case No. PUR-2018-00065. Customer forecasts are not available at the customer class level. The customer class breakdown is developed for the rate year as a part of the rate design methodology in the case.

(b) The Company's electric sales forecasts are available in its annual Integrated Resource Plan filings and Updates, the most recent of which was filed in Case No. PUR-2018-00065. Electric sales forecasts are not available at the customer class level. The customer class breakdown is developed for the rate year as a part of the rate design methodology in the case.

(c) The Company's revenue forecasts are available in its annual Integrated Resource Plan filings and Updates, the most recent of which was filed in Case No. PUR-2018-00065. The Company does not produce revenue forecasts at the customer class level.

(d) Please refer to the Company's response to Sierra Club Set 2-14(d). The Company does not forecast rates at the customer class level.

EXHIBIT TW/EM – 9

RESPONSE TO SIERRA CLUB 3-2

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 2 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 2

Please provide a table that includes the program energy savings (GWh) for all the programs implemented over the next ten years, including programs from Phases I through VII. Please break out the budgets/costs by phases and by programs. Provide the response in working electronic Excel format, with any formulas intact.

Response:

See the Company's response to Staff Set 1-2 for the requested information.

EXHIBIT TW/EM – 10

RESPONSE TO SIERRA CLUB 3-3

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 3 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 3

Please provide a table that includes the program demand savings (MW) for all the programs implemented over the next ten years, including programs from Phases I through VII. Please break out the budgets/costs by phases and by programs. Provide the response in working electronic Excel format, with any formulas intact.

Response:

See the Company's response to Staff Set 1-2 for the requested information.

EXHIBIT TW/EM – 11

RESPONSE TO SIERRA CLUB 3-4

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 4 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 4

Please provide a table that includes the expected number of participants for all the programs implemented over the next ten years, including programs from Phases I through VII. Please break out the budgets/costs by phases and by programs. Provide the response in working electronic Excel format, with any formulas intact.

Response:

See the Company's response to Staff Set 1-2 for the requested information.

EXHIBIT TW/EM – 12

RESPONSE TO SIERRA CLUB 3-5

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 5 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No. 5 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 5

The Grid Transformation and Security Act, Senate Bill 966, Section 56-599 requires Phase II utilities to spend $870 million on energy efficiency programs from July 2018 through July 2028. Please describe whether and how the Company's DSM Plan is consistent with this requirement. For all aspects that are not consistent, please explain why.

Response:

The Company objects to this request to the extent it seeks a legal conclusion. The Company also objects on the ground that "DSM Plan" is an undefined term and is vague. The Company further objects to this request to the extent it misstates the requirements of the Grid Transformation and Security Act, which requires the Company to "develop a proposed program of energy conservation measures" the projected costs of which "shall be no less than… $870 million for a Phase II Utility for the period beginning July 1, 2018, and ending July 1, 2028, including any existing approved energy efficiency programs." Subject to and notwithstanding this objection, the Company states as follows.

As stated on page 9 of the Company's Application in this proceeding, it is the Company's understanding that the total proposed costs of all energy efficiency programs being put forward in this proceeding will be counted towards the Grid Transformation and Security Act's ("GTSA") requirement that the Company propose programs to spend no less than an aggregate amount of $870 million between July 1, 2018 and July 1, 2028, including spend on continuing and approved energy efficiency programs since the July 1, 2018 effective date of the GTSA. The Company's Application in this proceeding represents of proposed program of energy conservation measures the cost of which total approximately $262 million.

EXHIBIT TW/EM – 13

RESPONSE TO SIERRA CLUB 2-5

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 5 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Jarvis E. Bates
Energy Conservation Compliance Consultant
Dominion Energy Virginia

Question No. 5

For each of the programs included in the Company's DSM Plan, please provide the annual costs broken out in detail, using the cost tracking categories used by the Company or the following cost categories:

(a) general administration and program development;
(b) customer incentive costs, including rebates, grants, energy audits, direct install labor costs, technical assessments and financing interest buy down costs;
(c) marketing, sales, call centers, website;
(d) training;
(e) inspections and quality control;
(f) evaluation, monitoring, measurement, and verification; and
(g) participant cost.

Response:

See the Company's response to Staff Set 1-2 and Extraordinarily Sensitive Attachment Staff Set 1-2 (JEB). Refer to Statement 4 for the requested information for the proposed Phase VII programs.

EXHIBIT TW/EM – 14

RESPONSE TO SIERRA CLUB 4-3

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 3 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No. 3 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 3

Refer to Hubbard's testimony, Schedule 3. For the programs in Phases I through VI that are still active, please provide tables, in working Excel files, that provide the budget spent, the kW savings, and the kWh savings achieved to date by year since implementation for each program.

Response:

The Company objects to this request on the grounds that it requires original work, which is not required by Rule 260 of the Commission's Rules of Practice and Procedure, 5 VAC 5-20-260. Subject to and notwithstanding this objection, the Company provides the following response.

Please refer to the Company's evaluation, measurement and verification ("EM&V") reports, which are filed annually in the DSM dockets. The most recent EM&V report was filed in on May 1, 2018 in Case No. PUE-2016-00111. The requested information is located in Appendices A and B.

EXHIBIT TW/EM – 15

RESPONSE TO SIERRA CLUB 5-1

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fifth Set

The following response to Question No. 1 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 24, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 1 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 24, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 1

Refer to the Company's response to Sierra Club 3-7. Please explain the specific differences between the DSM values included in the Company's DSM filing in the instant proceeding and the DSM values included in the Company's 2018 IRP. As part of the response, indicate the percent change in MWh savings between the two filings.

Response:

The Company objects to this request on the grounds that it requires original work to the extent it requests a calculation of the "percent change in MWh savings" between the 2018 IRP and this application, which is not required by Rule 260 of the Commission's Rules of Practice and Procedure, 5 VAC 5-20-260. Subject to and notwithstanding this objection, the Company provides the following response.

The 2018 IRP represents known DSM assumptions as of February 1, 2018. This filing represents responses received May 11, 2018, in response to a Company issued RFP, and specifically the programs evaluated and selected for inclusion as part of the Company's proposed DSM Phase VII.

EXHIBIT TW/EM – 16

THE NATIONAL EFFICIENCY SCREENING PROJECT, THE NATIONAL STANDARD PRACTICE MANUAL FOR ASSESSING THE COST-EFFECTIVENESS OF ENERGY EFFICIENCY RESOURCES (SPRING 2017)

National Standard Practice Manual

for Assessing Cost-Effectiveness of Energy Efficiency Resources

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NATIONAL EFFICIENCY SCREENING PROJECT

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for Assessing Cost-Effectiveness of Energy Efficiency Resources

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Prepared by
The National Efficiency Screening Project

The National Efficiency Screening Project

The National Efficiency Screening Project (NESP) is a group of organizations and individuals working to update and improve the way that utility customer-funded electricity and natural gas energy efficiency resources are assessed for cost-effectiveness and compared to other resource investments. This National Standard Practice Manual (NSPM) is a publication of the NESP.

The NSPM builds on the 2014 NESP publication *The Resource Value Framework – Reforming Energy Efficiency Cost Effectiveness Screening*, a foundational document that presented a first version of the Resource Value Framework. The NESP and 2014 publication, through the emergence of this NSPM, was managed and supported by the Home Performance Coalition, and is currently coordinated by E4TheFuture. We acknowledge the generous funding support over the years that made this project and report possible: the MacArthur Foundation, the United States Department of Energy, and E4TheFuture.

The NSPM, and related materials from the NESP, are available at: https://nationalefficiencyscreening.org

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Abstract

This National Standard Practice Manual (NSPM) is intended to provide a comprehensive framework for assessing the cost-effectiveness of energy efficiency resources. The manual is directly applicable to all types of electric and gas utilities and jurisdictions where energy efficiency resources are funded by and implemented on behalf of electric or gas utility customers. The intended audience are those involved in assessing the cost-effectiveness of energy resources, including regulators, utilities, program administrators, energy resource planners, consumer advocates, and other stakeholders.

The NSPM provides guidance that incorporates lessons learned over the past 20 years, responds to current needs, and addresses and takes into account the relevant policies and goals of each jurisdiction undertaking efficiency investments.

The NSPM presents an objective and neutral Resource Value Framework that can be used to define a jurisdiction's *primary* cost-effectiveness test, which is referred to as a Resource Value Test. The Resource Value Framework is based on six principles that encompass the perspective of a jurisdiction's applicable policy objectives, and it includes and assigns value to all relevant impacts (costs and benefits) related to those objectives.

The NSPM also provides information, guidance, and templates that support the selection of components of a jurisdiction's Resource Value Test (e.g., the range of costs and benefits to consider and appropriate discount rates), the application of such tests (e.g., defining of analysis periods), and the documentation of the relevant policies as well as quantification of relevant costs and benefits. The NSPM also addresses the use of secondary tests in addition to a primary Resource Value Test.

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Executive Summary

Assessing the cost-effectiveness of energy resources such as efficiency involves comparing the costs and benefits of such resources with other resources that meet energy and other applicable objectives. Historically, energy efficiency (EE) has been assessed through integrated resource planning processes or via standard tests defined in the California Standard Practice Manual (CaSPM). These assessments entail comparing the cost of EE resources to forecasts of avoided supply-side resources and other relevant costs and benefits. This National Standard Practice Manual (NSPM) builds and expands upon the decades old CaSPM, providing current experience and best practices with the following additions:

- Guidance on how to develop a jurisdiction's primary cost-effectiveness test that meets the applicable policy goals of the jurisdiction.[1] The guidance also addresses the difficulties jurisdictions have had in consistently implementing concepts presented in the CaSPM.
- Information on the inputs and considerations associated with selecting the appropriate costs and benefits to include in a cost-effectiveness test and accounting for applicable hard-to-monetize costs and benefits, with guidance on a wide range of fundamental aspects of cost-effectiveness analyses.

The NSPM presents:

- **Universal Principles** for developing and applying cost-effectiveness assessments.
- **A step-by-step Resource Value Framework** for jurisdictions to use to develop their primary cost-effectiveness test: **the Resource Value Test (RVT)**, which addresses all of the traditional components of cost-effectiveness testing – but with explicit consideration of the specific policy framework for the particular jurisdiction.
- **Neutral, objective guidance and foundational information** for selecting and quantifying the components of a jurisdiction's test(s), and for applying and documenting the policies and data that were used to define the test, building on lessons learned over the past 20 years and responding to current needs.

The NSPM is relevant to all types of electric and gas utilities, including: investor-owned utilities, publicly owned utilities, federal power authorities, and cooperatives, as well as to any jurisdiction where EE resources are funded and implemented on behalf of electric or gas utility customers.

While this NSPM focuses on the assessment of utility EE resources, the core concepts—including the principles described in Chapter 1 and the Resource Value Framework ('the Framework') described in Chapter 2—can generally be used to assess the cost-effectiveness of supply-side resources or distributed energy resources (DERs).

ES.1 Universal Principles

A unique attribute of the NSPM, and embedded in the Resource Value Framework, is a set of universal principles to follow when developing an RVT for any particular jurisdiction. These principles, provided in Table ES-1, represent sound economic and

[1] The NSPM uses the term "jurisdiction" broadly to encompass states, provinces, federal power authorities, municipalities, cooperatives, etc.

regulatory practices, and are consistent with the input received from a broad range of stakeholders during the development of this manual.

Table ES-1. Universal Principles

Efficiency as a Resource	EE is one of many resources that can be deployed to meet customers' needs, and therefore should be compared with other energy resources (both supply-side and demand-side) in a consistent and comprehensive manner.
Policy Goals	A jurisdiction's primary cost-effectiveness test should account for its energy and other applicable policy goals and objectives. These goals and objectives may be articulated in legislation, commission orders, regulations, advisory board decisions, guidelines, etc., and are often dynamic and evolving.
Hard-to-Quantify Impacts	Cost-effectiveness practices should account for all relevant, substantive impacts (as identified based on policy goals,) even those that are difficult to quantify and monetize. Using best-available information, proxies, alternative thresholds, or qualitative considerations to approximate hard-to-monetize impacts is preferable to assuming those costs and benefits do not exist or have no value.
Symmetry	Cost-effectiveness practices should be symmetrical, where both costs and benefits are included for each relevant type of impact.
Forward-Looking Analysis	Analysis of the impacts of resource investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of the subject resources as compared to the costs and benefits that would occur absent the resource investments.
Transparency	Cost-effectiveness practices should be completely transparent, and should fully document all relevant inputs, assumptions, methodologies, and results.

ES.2 Resource Value Framework

The Resource Value Framework is used to construct a jurisdiction's primary cost-effectiveness test, the RVT, using a series of seven steps that define the framework. In some cases, the steps align directly with one of the universal principles.

The Framework encompasses the perspective of a jurisdiction's applicable policy objectives, and it includes and assigns value to all relevant impacts (costs and benefits) related to those objectives. The NSPM refers to this as the 'regulatory' perspective, which is intended to reflect the important responsibilities of institutions, agents, or other decision-makers authorized to determine utility resource cost-effectiveness and funding priorities. This perspective flows from the notion that determining whether a resource has benefits that exceed its costs requires clarity about the purpose of the resource investment decision.

> **Regulators/decision-makers** refers to institutions, agents, or other decision-makers that are authorized to determine utility resource cost-effectiveness and funding priorities. Such institutions or agents include public utility commissions, legislatures, boards of publicly owned utilities, the governing bodies for municipal utilities and cooperative utilities, municipal aggregator governing boards, and more.

The NSPM further provides information, templates, and examples that can support a jurisdiction in applying the universal principles, and also in constructing appropriate tests in a structured, logical, and documented manner that meets the specific interests and needs (as defined by policies) of the jurisdiction. The seven steps of the Framework are summarized in Figure ES-1 below.

Figure ES-1. Resource Value Framework Steps

STEP 1	Identify and articulate the jurisdiction's applicable policy goals.
STEP 2	Include all the utility system costs and benefits.
STEP 3	Decide which non-utility impacts to include in the test, based on applicable policy goals.
STEP 4	Ensure that the test is symmetrical in considering both costs and benefits.
STEP 5	Ensure the analysis is forward looking and incremental.
STEP 6	Develop methodologies to account for all relevant impacts, including hard to quantify impacts.
STEP 7	Ensure transparency in presenting the inputs and results of the cost-effectiveness test.

ES.3 Resource Value Test

The RVT is the primary cost-effectiveness test designed to represent a regulatory perspective, which reflects the objective of providing customers with safe, reliable, low-cost energy services, while meeting a jurisdiction's other applicable policy goals and objectives. As described in detail within the NSPM, each jurisdiction can develop its own RVT using the Resource Value Framework.

The RVT focus on the regulatory perspective differs from the three most common CaSPM traditional tests—the Utility Cost Test (UCT), Total Resource Cost (TRC) test and Societal Cost Test (SCT). These tests provide the perspective of the utility, the utility and participants, and society as a whole, respectively.

The RVT and Secondary Tests

The RVT serves as a primary test which assesses cost-effectiveness of efficiency resources relative to a jurisdiction's applicable policy goals that are under the purview of the jurisdiction's regulators or other decision-makers. However, there can be value in assessing cost-effectiveness of efficiency resources from perspectives represented by other tests. Among the potential purposes of using additional tests are:

- To inform decisions regarding how much utility customer money could or should be invested to acquire cost-effective savings;
- To inform decisions regarding which efficiency programs to prioritize if not all cost-effective resources will be acquired;
- To inform efficiency program design; and/or
- To inform public debate regarding efficiency resource acquisition.

Depending on a jurisdiction's energy and other applicable policy goals, the resulting RVT may or may not be different from the traditional cost-effectiveness tests. Put another way, it is possible for a jurisdiction's applicable policy goals to align with one of the traditional CaSPM tests, in which case its RVT will be identical to one of those tests. However, it is also possible—and indeed likely in many cases—that a jurisdiction's energy and other policy goals will not align well with goals implicit in any of the traditional tests. In such cases, the RVT will be different than all the traditional tests.

Furthermore, each jurisdiction's RVT can be unique, where the categories of impacts included in the RVT can vary across jurisdictions and/or over time. This is because the impacts are based on each jurisdiction's policy concerns, which can and do vary. *In contrast, the traditional UCT, TRC, and SCT tests are conceptually static; they do not change geographically or over time if applied in their purest conceptual form.* Table ES-2 compares the RVT with the CaSPM tests.

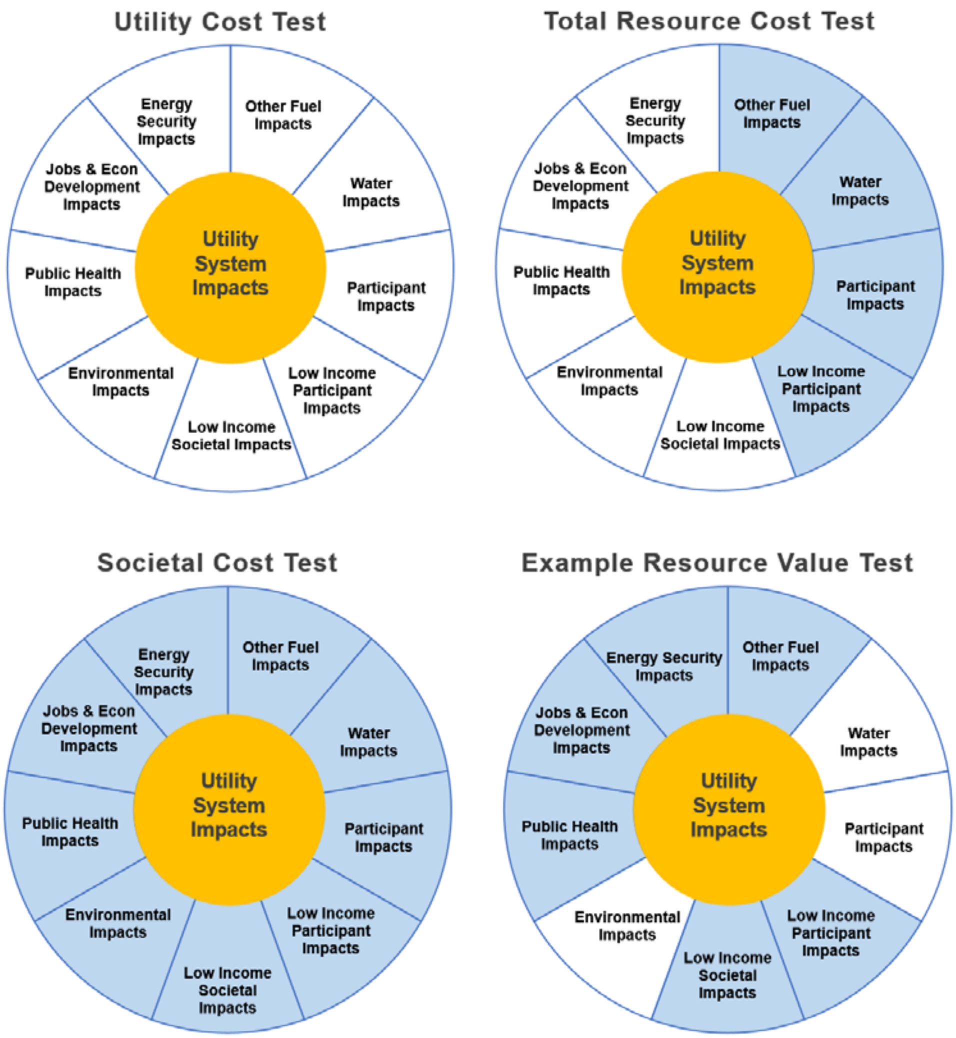
Table ES-2. Comparison of RVT with the Traditional CaSPM Tests

Test	Perspective	Key Question Answered	Categories of Costs and Benefits Included
Utility Cost Test	The utility system	Will utility system costs be reduced?	Includes the costs and benefits experienced by the utility system
Total Resource Cost Test	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the costs and benefits experienced by society as a whole
Resource Value Test	Regulator/decision makers	Will utility system costs be reduced, while achieving applicable policy goals?	Includes the utility system costs and benefits, plus those costs and benefits associated with achieving relevant applicable policy goals

In those cases where a jurisdiction's policy goals align with one of the other tests, the RVT will be the same as that other test. This is discussed in Chapter 4.

Figure ES-1 compares the traditional cost-effectiveness tests to one that is developed using the Resource Value Framework. The gold circle in the center represents the utility system impacts, which should be included in any cost-effectiveness test. The sections around the circles represent non-utility system impacts that jurisdictions can choose to include in their primary test. Three of the circles indicate the impacts that would be included using the traditional cost-effectiveness tests. The fourth circle indicates a different set of impacts that would be included by a jurisdiction whose policies suggest accounting for other fuel impacts, low-income impacts, public health impacts, jobs and economic development, and energy security.

Figure ES-1. Examples of Primary Tests that Jurisdictions Could Develop Using the Resource Value Framework



To support the core principle to transparently document cost-effectiveness practices, this NSPM presents an RVT template, shown in Table ES-3, to assist jurisdictions in documenting assumptions and results of their analysis. More detail with examples is provided in Part I of the NSPM.

Table ES-3: Efficiency Cost-Effectiveness Reporting Template

Program/Sector/Portfolio Name:		Date:	
A. Monetized Utility System Costs		**B. Monetized Utility System Benefits**	
Measure Costs (utility portion)		Avoided Energy Costs	
Other Financial or Technical Support Costs		Avoided Generating Capacity Costs	
Program Administration Costs		Avoided T&D Capacity Costs	
Evaluation, Measurement, & Verification		Avoided T&D Line Losses	
Shareholder Incentive Costs		Energy Price Suppression Effects	
		Avoided Costs of Complying with RPS	
		Avoided Environmental Compliance Costs	
		Avoided Bad Debt, Arrearages, etc.	
		Reduced Risk	
Sub-Total Utility System Costs		**Sub-Total Utility System Benefits**	
C. Monetized Non-Utility Costs		**D. Monetized Non-Utility Benefits**	
Participant Costs	*Include to the extent these impacts are part of the RVT.*	Participant Benefits	*Include to the extent these impacts are part of the RVT.*
Low-Income Customer Costs		Low-Income Customer Benefits	
Other Fuel Costs		Other Fuel Benefits	
Water and Other Resource Costs		Water and Other Resource Benefits	
Environmental Costs		Environmental Benefits	
Public Health Costs		Public Health Benefits	
Economic Development and Job Costs		Economic Development and Job Benefits	
Energy Security Costs		Energy Security Benefits	
Sub-Total Non-Utility Costs		**Sub-Total Non-Utility Benefits**	
E. Total Monetized Costs and Benefits			
Total Costs (PV$)		**Total Benefits (PV$)**	
Benefit-Cost Ratio		**Net Benefits (PV$)**	
F. Non-Monetized Considerations			
Economic Development and Job Impacts	*Quantitative information, and discussion of how considered*		
Market Transformation Impacts	*Qualitative considerations, and discussion of how considered*		
Other Non-Monetized Impacts	*Quantitative information, qualitative considerations, and how considered*		
Determination:	**Do Efficiency Resource Benefits Exceed Costs? [Yes / No]**		

ES.4 Applicability to Other Types of Resources

While this NSPM focuses on the assessment of EE resources, the core concepts can be applied to other types of resources as well. The cost-effectiveness principles described in Chapter 1, and the Resource Value Framework described in Chapter 2, can be used to assess the cost-effectiveness of supply-side resources or distributed energy resources (DERs)—including EE, demand response, distributed generation, distributed storage, electric vehicles, and strategic electrification technologies.

With regard to supply-side resources, the cost-effectiveness principles can be used in the context of integrated resource planning or when conducting any sort of economic analyses of specific generation, transmission, or distribution infrastructure investments. The Resource Value Framework can be used to identify the primary test for assessing these supply-side investments, or to identify the criteria that would be used to select the preferred resource plan in the context of an IRP. This approach would not only ensure sound practices for analyzing supply-side resources, it would also ensure that EE resources are analyzed comparably and consistently with supply-side resources.

With regard to DERs, the cost-effectiveness principles and the Resource Value Framework can be used as the foundation for assessing their cost-effectiveness. There are, however, ways in which other types of DERs might need to be treated differently from EE resources. These important DER-specific issues are beyond the scope of this NSPM, but should be addressed by each jurisdiction as they develop cost-effectiveness practices for DERs.

ES.5 Foundational Information Covered in the NSPM

Supporting the implementation of the Resource Value Framework for developing an RVT requires understanding of a wide range of cost-effectiveness related topics. These include identifying, quantifying, and documenting relevant policies, costs, and benefits—in addition to the analysis of related foundational considerations of cost-effectiveness tests. Thus, the NSPM not only presents the universal principles, the Framework, and associated RVT concepts and examples, but also provides information on related foundational topics that can be particularly valuable to those responsible for developing the RVT and its inputs. The NSPM can also be helpful for those seeking to understand the range of options and outcomes that can result from different RVTs.

> **Questions the RVT Does and Does Not Answer**
>
> The primary RVT can be used to answer the fundamental question of *which resources have benefits that exceed their costs*, where the benefits and costs are defined by the applicable policy goals of a jurisdiction and developed via Framework 7-step process. With this Framework, the resource investment decision question is addressed in a comprehensive and transparently documented manner.
>
> Regulators and decision-makers typically need to answer a second critical question: *how much utility customer funding should be spent on EE resources?* The primary cost-effectiveness test is necessary but may not be sufficient for answering this second question, which requires consideration of jurisdiction-specific factors through a process such as integrated resource planning or rate proceedings.

The foundational topics covered in the NSPM, found in Parts I, II, or in the appendices, are as follows:

- Ensuring transparency of the assumptions, analysis and results (Chapter 3)

- Use of primary vs secondary cost-effectiveness tests (Chapter 5)
- Identifying relevant impacts (costs and benefits) to include in a Resource Value Test (Chapter 6)
- Methods that can be used to determine or account for all relevant impacts (Chapter 7)
- Considerations for including Participant Impacts (Chapter 8)
- Identifying appropriate discount rates (Chapter 9)
- Selecting an assessment level (Chapter 10)
- Selection of an analysis period (Chapter 11)
- Treatment of Early Replacement (Chapter 12)
- Treatment of Free Riders and Spillover (Chapter 13)
- Traditional Cost-Effectiveness Tests (Appendix A)
- DER Costs and Benefits (Appendix B)
- Accounting for Rate and Bill Impacts (Appendix C)

INTRODUCTION: Purpose, Scope and Format

Purpose

The purpose of this National Standard Practice Manual (NSPM) is to help guide the development of a cost-effectiveness test for regulators, utilities, program administrators, efficiency planners, consumer advocates, and other efficiency stakeholders. In its simplest form, assessing the cost-effectiveness of energy resources involves comparing the costs and benefits of such resources with other resources. The manual describes the principles, concepts, and methodologies for sound, comprehensive, balanced assessment of the cost-effectiveness of EE resources, and can help involved parties identify the full range of efficiency resources whose benefits exceed their costs. Utility resource decision-makers can then use this information to decide which resources to acquire to meet their specific EE objectives, standards, or targets.

> **This manual is intended to serve as an objective, neutral guidance document that does not prescribe any one type of cost-effectiveness test *per se*.**

This manual is intended to serve as an objective, neutral guidance document that does not prescribe any one type of cost-effectiveness test *per se*. Rather it sets forth a framework that includes key principles and steps to use within a jurisdiction to develop a primary cost-effectiveness test, and also to inform use of secondary tests.

The goal of this manual is to provide guidance that: (1) builds from the lessons learned over the past decades, (2) responds to current needs, (3) addresses the specific goals of each jurisdiction, and (4) can eventually be fully expanded to address all types of distributed energy resources (DER).

Why the Need for this NSPM?

Since the 1980s, the prevailing cost-effectiveness guidance document for EE resources has been the *California Standard Practice Manual* (CaSPM), which sets forth several ‘traditional tests’ commonly referred to as the Utility Cost Test (UCT), the Total Resource Cost (TRC) test, and the Societal Cost Test (SCT).[2] Last updated in 2002, the CaSPM presents important limitations with which jurisdictions have increasingly struggled over the years. This has led to the inconsistent application of the traditional tests. These limitations are generally characterized as follows:

a) The CaSPM does not provide guidance on how to develop a cost-effectiveness *framework*, and associated primary test, that reflects a jurisdiction’s energy and

[2] See Appendix A for a summary of the Traditional Tests. The CA SPM’s chapters are organized around 4-5 tests: the Participant Test; the RIM test; the TRC test; the SCT (characterized as a variant of the TRC); and the Program Administrator Costs test, also referred to as the Utility Cost Test (UCT). This manual focuses on the most commonly used cost-effectiveness tests in practice today: the TRC test, UCT, and SCT.

other applicable policy goals. Such goals should be directly relevant to identifying the range of costs and benefits to include in a jurisdiction's cost-effectiveness analyses.

b) The three commonly used traditional tests (UCT, TRC, and SCT) are typically defined as having a specific set of costs and benefits depending on the perspective of either the utility, the utility and program participants, or society as a whole.[3] A jurisdiction's energy policies, however, seldom align precisely with any one of these types of perspectives. Moreover, these three tests do not account for a critical perspective: the perspective of reducing total utility costs to customers (relative to other resources) while also explicitly taking into account the jurisdiction's applicable policy goals. That broader perspective is intended to be reflective of the important responsibilities of a utility regulator. Hence the NSPM introduces this concept as the *regulatory perspective*.

c) Jurisdictions have struggled with ongoing debates about what costs and benefits should be included in their analyses, and whether and/or how to account for certain impacts. This is especially the case for hard-to-quantify non-energy impacts. These issues have been particularly challenging for the TRC test, the predominantly used screening test. Research has shown that most jurisdictions that use the TRC test treat costs and benefits asymmetrically by accounting for participant costs but not benefits (ACEEE 2012). The CaSPM lacks key principles and guidance that can help jurisdictions determine which impacts to consider. It further lacks options for how to account for such impacts, including those that are difficult to quantify.

Over time, implementation across the states has led to inconsistent application of the traditional tests. The result has been a myriad of variations of the tests, in particular the TRC test. For example, a TRC test in one state can look more like an SCT (e.g., due to the inclusion of environmental impacts), and TRC test results from one state to another often vary considerable due to different treatment of non-energy benefits where many states do not include benefits that are hard to quantify, thus resulting in asymmetrical treatment of costs and benefits. As a result, the benefit-cost ratios of similar programs using the TRC test are not comparable across jurisdictions—and the test itself is no longer the TRC test in its pure and intended definition.

More broadly, as the electricity industry evolves to increasingly plan for and implement DERs, there is a need for a comprehensive cost-effectiveness framework that jurisdictions can use to apply to all DERs. The core principles and concepts in this NSPM can be used as the foundation for developing cost-effectiveness practices for all types of DERs.

Scope of this Manual

This NSPM focuses on the assessment of EE resources whose acquisition is funded by, and implemented on behalf of, electricity and gas utility customers, and where the value of efficiency resources is assessed using estimates of avoided utility system costs and other relevant impacts. The manual is intended as a tool to inform decision-making regarding which particular EE program (or set of programs) should be implemented using customer funding.

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[3] While most jurisdictions have historically used the CaSPM as the foundation for their cost-effectiveness tests, in practice many jurisdictions have deviated from those tests.

Note that the cost-effectiveness practices described in this manual are similar to integrated resource planning (IRP) practices, but different in some important respects.

The concepts in this NSPM can also apply to the assessment of other types of efficiency resources, such as building codes and appliance standards, government-funded efficiency resources, tax incentives for efficiency improvements, and more. However, this manual is focused on the assessment of ratepayer-funded EE programs because these programs have different types of costs and benefits and typically require more regulatory review and oversight.

Integrated Resource Planning (IRP) – the Other Way to Assess Cost Effectiveness

Some jurisdictions use long-term, IRP to help identify the portfolio of resources (supply-side and demand-side) that is least-cost and meets energy policy goals. Such IRP processes typically involve optimizing the costs, performance, and other attributes of all resource options in a dynamic fashion using optimization models, scenario analyses, and sensitivity analyses.

The cost-effectiveness practices described in this manual are similar to IRP practices, but different in some important respects. Both practices compare the long-run, marginal costs of different scenarios of resources to identify those with benefits that exceed costs, and both should use similar inputs regarding the future costs of EE, demand-side, and supply-side resources.

However, IRP and cost-effectiveness testing differ in that IRP typically allows for more sophisticated analyses of the impacts of EE impacts on utility system costs (e.g., modeling of EE loadshape impacts on power plant dispatch over time), and provides more flexibility for conducting scenario analyses and sensitivity analyses. On the other hand, though perhaps less dynamic, cost-effectiveness analyses using fixed avoided cost assumptions is commonly used to assess EE at a more granular level. It allows for assessment of a range of different types of programs, program designs, and even efficiency measures.

Applicability to Other Types of Utility Resources

While this NSPM focuses on the assessment of utility EE resources, the core concepts can be applied to other types of utility resources as well. The cost-effectiveness principles described in Chapter 1 and the Resource Value Framework described in Chapter 2 can be used to assess the cost-effectiveness of supply-side or distributed energy resources—including EE, demand response, distributed generation, distributed storage, electric vehicles, and strategic electrification technologies.

With regard to supply-side resources, the cost-effectiveness principles can be used in the context of integrated resource planning or when conducting any sort of economic analyses of specific generation, transmission, or distribution infrastructure investments. The Resource Value Framework can be used to identify the primary test for assessing these supply-side investments, or to identify the criteria that would be used to select the preferred resource plan in the context of an IRP. This approach would not only ensure sound practices for analyzing supply-side resources, it would also ensure that EE resources are analyzed comparably and consistently with supply-side resources.

With regard to DERs, the principles and Resource Value Framework can be used as the foundation for assessing their cost-effectiveness.[4] However, there are important ways in

[4] Most recent studies of DER cost-effectiveness use the CaSPM as a starting point. See for example (IREC 2013), (NYSERDA 2015), and (Consumers Union 2016).

which other types of DERs might need to be treated differently from EE resources. For example:

- Some costs and benefits of EE might not be applicable to other types of DER, and vice versa. Some of the costs and benefits of EE might have different magnitudes relative to other types of DERs, including time-varying differences and locational differences.[5]
- The approach for addressing rate, bill, and participant impacts might be different for different types of DERs.
- In some jurisdictions, the policy goals supporting other types of DERs might be different from those supporting EE.

These important DER-specific issues are beyond the scope of this NSPM, but should be addressed by each jurisdiction as they develop cost-effectiveness practices for DERs. In the future, this EE manual could be expanded to address these other types of DER specific issues.

How this Manual Differs from the California Standard Practice Manual

This Manual builds upon the concepts and techniques of the CaSPM by addressing limitations and applying lessons learned over the years in the use of the CaSPM "traditional" tests. The NSPM expands on the CaSPM in various ways:

1. It provides a set of *universal principles* that should be used to guide the development of cost-effectiveness tests.
2. It includes the foundational principle that a jurisdiction should consider *applicable policy goals* when developing its primary cost-effectiveness test; it thereby introduces the perspective of the regulator/agent relative to the relevant policy goals, which may differ from the perspectives provided in the CaSPM.
3. Rather than specify a set of pre-defined tests, it provides *a framework and a process* for a jurisdiction to develop *its own specific primary test* (or tests).
4. It provides more information on the different types of EE resource costs and benefits, and how they should be treated when developing a cost-effectiveness test.
5. It provides guidance on how to account for applicable hard-to-monetize costs and benefits, as well as guidance on how to apply qualitative considerations.
6. It provides guidance on how to develop inputs for cost-effectiveness tests, such as discount rates, early replacement of measures, free-riders, and spillover.

[5] Appendix B provides a comparison of costs and benefits of EE relative to other types of DERs.

Format of this Manual

Guidance on the Resource Value Framework and associated RVT is organized as follows:

Part I provides guidance on *how to develop* cost-effectiveness tests using the Resource Value Framework. It sets forth the set of universal principles that can be applied to any cost-effectiveness assessment, and provides a step-by-step process for jurisdictions to use to develop their primary RVT. Examples are provided, along with guidance on the use of secondary tests.

Part II provides more detailed information to assist jurisdictions in *developing inputs* for their RVTs, with guidance on what to include or not in the test by applying the Resource Value Framework process, and determining values for the inputs used in their primary test.

Appendices provide further detail on topics which may be relevant for some jurisdictions.

The intended audience for Part I is for regulators and other decision makers, policymakers, program administrators, EE and other DER stakeholders, evaluators, and other EE practitioners. Part II provides detailed guidance on key topics for those interested in delving into more details.

Table 1 shows the layout of the NSPM, with descriptions of the topics covered in each chapter.

Table 1. Overview of the National Standard Practice Manual

Part/Chapter	Topic	Description
Part I	**Developing Cost-Effectiveness Tests Using the Resource Value Framework**	
Chapter 1	Principles	Describes the key principles that should be applied in any resource cost-effectiveness assessment
Chapter 2	The Resource Value Framework	Provides an overview of the Framework and embodied principles, describes the dynamic nature of the RVT and its relevance to traditional cost-effectiveness tests
Chapter 3	Developing the Resource Value Test (RVT)	Sets forth the multi-step process for developing a primary test based on principles and framework set forth in Chapters 1-2; provides templates to document applicable policies, inputs, and results using a standard format
Chapter 4	RVT Relationship to Traditional Tests	Provides examples of hypothetical RVTs, and describes how a jurisdiction's RVT could compare to the traditional tests: UCT, TRC and SCT
Chapter 5	Secondary Cost-Effectiveness Tests	This chapter provides information about the potential role of secondary tests, their benefits and limits, and selecting and constructing such tests
Part II	**Developing Inputs for Cost-Effectiveness Tests**	
Chapter 6	Energy Efficiency Costs and Benefits	Describes the range of EE costs and benefits, both utility system and non-utility system, and information for selecting impacts to include in tests
Chapter 7	Methods to Account for Relevant Impacts	Provides guidance on options for accounting for relevant cost and benefits, including hard-to-quantify impacts as well as approaches for qualitatively including non-monetary impacts
Chapter 8	Participant Impacts	Expands upon guidance in Chapter 3 regarding how to determine whether to include participant impacts in the RVT
Chapter 9	Discount Rates	Describes ways to determine discount rates that are consistent with the jurisdiction's applicable policy goals
Chapter 10	Assessment Level	Describes the advantages and disadvantages of assessing EE at measure, program, or portfolio levels, and assessment level for fixed costs
Chapter 11	Analysis Period and End Effects	Describes the time period over which cost-effectiveness analysis should be conducted, and how to address any potential "end effects" problems
Chapter 12	Early Replacement	Describes how to analyze the costs and benefits of replacing operating equipment before the end of its useful life
Chapter 13	Free-Riders and Spillover	Describes how to address free-riders and spillover effects in cost-effectiveness analyses for jurisdictions that use net savings
Appendices		
Appendix A	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the California Standard Practice Manual
Appendix B	DER Costs and Benefits	Summarizes similarities and differences in costs and benefits across different types of DERs
Appendix C	Rate and Bill Impacts	Describes key factors affecting rates and bills, and an approach for assessing related trade-offs
Appendix D	Glossary of Terms	Provides definitions for commonly used terms throughout the manual

Key Terminology Used in this Manual

Terms with specific meaning in the context of the concepts offered in this NSPM are provided below, with additional terms in Appendix D.

- Avoided costs, refers to the costs of those electricity and gas resources that are deferred or avoided by the EE resources being evaluated for cost-effectiveness. The avoided costs are what make up the utility system benefits of EE resources.
- Distributed energy resources (DERs), refers to electricity and gas resources that are installed on customers' premises (behind the meter), to improve customer consumption patterns and reduce customer costs. These include EE, demand response, distributed generation, storage, plug-in electric vehicles, strategic electrification technologies, and more.
- Energy efficiency resource, refers to EE technologies, services, measures, or programs funded by, and promoted on behalf of, electricity and gas utility customers.
- Impacts, refers to both the costs and the benefits of a supply-side or demand-side resource.
- Jurisdiction, refers to states, provinces, utilities, municipalities, or other regions for which EE resources are planned and implemented.
- Primary cost-effectiveness test, refers to the cost-effectiveness framework that a jurisdiction most relies upon when choosing the efficiency resources in which to invest ratepayer money.
- Regulators and Other Decision Makers, refers to institutions, agents, or other decision-makers that are authorized to determine utility resource cost-effectiveness and funding priorities. Such institutions or agents include public utility commissions, legislatures, boards of publicly owned utilities, the governing bodies for municipal utilities and cooperative utilities, municipal aggregator governing boards, and more.
- Regulatory perspective, refers to the perspective of regulators or other agents that oversee efficiency resource investment choices. This perspective is guided by the jurisdiction's energy and other applicable policy goals—whether in laws, regulations, organizational policies, or other codified forms—under which they operate.
- Resource Value Framework, refers to a series of seven steps that can guide any jurisdiction to develop its primary test for assessing EE (and other DERs) cost-effectiveness. The Resource Value Framework embodies the key principles of cost-effectiveness analyses described in Chapter 1.
- Resource Value Test (RVT), refers to the primary cost-effectiveness test that a jurisdiction has developed using the Resource Value Framework. It embodies all of the key principles of cost-effectiveness analyses and accounts for that jurisdiction's applicable policy goals.
- Utility system, refers to all elements of the electricity or gas system necessary to deliver services to the utility's customers. For electric utilities, this includes generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations. This term refers to any type of utility ownership or management, including investor-owned utilities, publicly owned utilities, municipal utility systems, cooperatives, etc.

PART I.
Developing Cost-Effectiveness Tests Using the Resource Value Framework

1. Principles of Cost-Effectiveness Analyses

This chapter presents the six core principles that are embodied in the Resource Value Framework and are fundamental to helping guide jurisdictions in the development of their primary cost-effectiveness test. These principles represent sound economic and regulatory practices and are consistent with the input received from a wide range of stakeholders during the development of this manual.

The following principles should be applied when developing and applying a jurisdiction's primary EE cost-effectiveness test:

1. **Efficiency as a Resource.** EE is one of many resources that can be deployed to meet customers' needs, and therefore should be compared with other energy resources (both supply-side and demand-side) in a consistent and comprehensive manner.
2. **Applicable Policy Goals.** A jurisdiction's primary cost-effectiveness test should account for its energy and other applicable policy goals. These goals may be articulated in legislation, commission orders, regulations, advisory board decisions, guidelines, etc., and are often dynamic and evolving.
3. **Hard-to-Quantify Impacts.** Cost-effectiveness practices should account for all relevant, substantive impacts (as identified based on policy goals,) even those that are difficult to quantify and monetize. Using best-available information, proxies, alternative thresholds, or qualitative considerations to approximate hard- to- monetize impacts is preferable to assuming those costs and benefits do not exist or have no value.
4. **Symmetry.** Efficiency assessment practices should be symmetrical, for example by including both costs and benefits for each relevant type of impact.
5. **Forward Looking**. Analysis of the impacts of efficiency investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of efficiency measures and those that would occur absent the efficiency investments.[6]
6. **Transparency.** Efficiency assessment practices should be completely transparent and should fully document all relevant inputs, assumptions, methodologies, and results.

These principles are relevant to cost-effectiveness analyses of any resource, supply or demand, and are embodied within the Resource Value Framework provided in this manual. The key issues associated with their application to such analyses will differ

[6] As further discussed in this chapter, sunk costs and benefits are not relevant to a cost-effectiveness analysis.

somewhat from resource to resource, depending on the unique characteristics of each resource.

Principle #1: Efficiency as a Resource

EE is a resource that can be used to defer or avoid spending on other electricity or gas resources. Consequently, an EE cost-effectiveness assessment should enable a full and fair assessment of the benefits and costs of the efficiency resource relative to other types of resources. The assessment should include comparisons to both supply-side resources and other demand resources to ensure accurate results. This principle necessitates that utility system costs and benefits always be included in cost-effectiveness analyses (see more detailed discussion in Chapter 3).

Principle #2: Applicable Policy Goals

A jurisdiction's EE cost-effectiveness framework should account for the energy and other applicable policy goals and objectives that apply to that jurisdiction. The choice between an investment in EE or investments in other demand and/or supply resources—i.e., what happens if efficiency investments are not made—can materially affect the costs, timeframe, and even ability to achieve such other policy goals. Cost-effectiveness analyses should guide or inform resource choices in that context.

Each jurisdiction's primary cost-effectiveness should recognize the full "resource value" of EE.

Thus, each jurisdiction's primary cost-effectiveness test should include all categories of relevant impacts (costs and benefits) consistent with its applicable policy goals. In other words, each jurisdiction's primary cost-effectiveness should recognize the full "resource value" of EE.

'Regulators/decision-makers' refers to all types of entities that oversee EE investments such as: utility regulators; boards or management teams of unregulated municipal or cooperative utilities; or federal, regional, or state power planning agencies.

A jurisdiction's applicable policy goals are formally stated policy objectives that provide the overall policy context within which regulators and other agents make decisions regarding utility resource investments. These goals can be articulated in several different ways, including: legislation; executive orders; regulations; commission or board guidelines, standards or orders; and other pronouncements from a relevant governing agency. Importantly, identifying applicable policies for a jurisdiction is not a static process, but likely to evolve. For example, some jurisdictions may not have explicit statutes or regulations that address certain impacts that have been identified as important by stakeholders. In these instances, stakeholder input and due process often inform such policy development.

Energy and other applicable policy goals often evolve over time in response to changes in the energy industries, changing perspectives from the legislature and regulators, and the evolving interests of and input from industry stakeholders. As such, identifying applicable policies for a jurisdiction is not a static process, but likely to evolve (e.g., as part of regulatory processes and stakeholder discussions.) The jurisdiction's cost-effectiveness test(s) may need to periodically evolve as well.

Table 2 below provides examples of policy goals. Some of these goals may overlap with each other, as is the case with reducing system risk and promoting resource diversity. Others may sometimes conflict with each other, as with reducing utility system costs and improving reliability, promoting customer equity, and/or reducing environmental impacts. Such trade-offs can only be systematically assessed and EE investment decisions can only be optimized if cost-effectiveness analyses account for all categories of impacts relevant to the jurisdiction's goals. Importantly, the constellation of applicable policy goals in any one jurisdiction is likely to differ in some ways from that of other jurisdictions.

Table 2. Examples of Energy-Related and Other Applicable Policy Goals[7]

Common Overarching Goals: Provide safe, reliable, low-cost electricity and gas services; protect low-income and vulnerable customers; maintain or improve customer equity.
Efficiency Resource Goals: Reduce electricity and gas system costs; develop least-cost energy resources; promote customer equity; improve system reliability and resiliency; reduce system risk; promote resource diversity; increase energy independence (and reduce dollar drain from the jurisdiction); reduce price volatility.
Other Applicable Goals: Support fair and equitable economic returns for utilities; provide reasonable energy costs for consumers; ensure stable energy markets; reduce energy burden on low-income customers; reduce environmental impact of energy consumption; promote jobs and local economic development; improve health associated with reduced air emissions and better indoor air quality.

Finally, this principle serves as a fundamental first step in developing a jurisdiction's primary cost-effectiveness—the RVT, as discussed in Chapters 2 and 3. The primary test thus reflects a mix of various perspectives impacted by the jurisdiction's applicable policies, otherwise referred to within this NSPM as the 'regulatory' perspective.

> Fundamental to Principle #2 is the **concept of the 'regulatory' perspective**, which includes consideration of the full scope of issues for which regulators/decision-makers are responsible: (1) overall objective of requiring electricity/gas utilities to provide safe, reliable, low-cost services to customers; and (2) meeting their jurisdiction's other applicable policy goals.

Principle #3: Hard-to-Quantify Impacts

Ideally, all costs and benefits of EE resources that are relevant to a jurisdiction's applicable policy goals should be estimated in monetary terms, so that they can be directly compared.

Some impacts are challenging to quantify and put into monetary terms. Data may not be readily available, studies may require a considerable amount of time and/or resources to implement, and such studies might still result in significant uncertainty. That can be the case for impacts that are common to assessment of any type of resource. Examples include some utility system impacts (e.g., forecasts of resource needs and costs, impacts of future government regulations, and the magnitude and value of risk mitigation) as well as impacts that can be relevant to other jurisdictional policy objectives (e.g., value of reduced environmental impacts). It can also be the case for some impacts that may be unique to efficiency resources (e.g., benefits of improved comfort or business productivity).

Nevertheless, efficiency costs and benefits that are relevant to a jurisdiction's applicable policy goals and that can reasonably be assumed to be real and substantial should not be excluded or ignored because they are difficult to quantify and monetize. There are a

[7] This list is not intended to be exhaustive, nor is it intended to imply a recommendation of any policies for any jurisdiction. It is intended to illustrate the types of policies that jurisdictions typically establish.

variety of ways to develop estimates of impacts that are reasonable enough to inform investment decisions (see discussion in Chapter 7). Using "best available" information to approximate hard-to- quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value. In a worst-case scenario, excluding substantive impacts from efficiency resource assessment will lead to results that are inaccurate and misleading.

Using "best available" information to approximate hard-to-quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value.

Principle #4: Symmetry

For each type of impact included in a cost-effectiveness test, it is important that both the costs and the benefits be included in a symmetrical way. Otherwise, the test may be skewed and provide misleading results.

For starters, this means that all utility system costs (i.e., costs of running efficiency programs) and all utility system benefits (see Chapter 6 for a more detailed discussion of the range of utility system benefits) should be included in cost-effectiveness analyses.

It is important that both the costs and the benefits be included in a symmetrical way. Otherwise, the test may be skewed and provide misleading results.

In addition, if a jurisdiction's applicable policy goals dictate that impacts on efficiency program participants be included in its cost-effectiveness test, then both costs borne by those participants and benefits received by those participants should be included. On the cost side, this would most commonly be a portion of the efficiency measure costs (e.g., if the incremental cost of an efficiency measure is $1,000 and the utility program is providing a rebate of $300, then the participants are incurring the remaining $700 cost).[8] On the benefits side, depending on the measures or program, there may be a variety of non-energy benefits that are part of the reason a customer invested in the measure (e.g., improved comfort, improved building durability, improved business productivity, etc.). If the participant costs are included in the cost-effectiveness test, then such benefits would need to be included as well.

Similarly, if a jurisdiction's applicable policies dictate that other categories of impacts should be included in its cost-effectiveness test—whether other fuel, water, low income, environmental, public health, economic development, and/or other impacts—then all incremental[9] negative (cost) and positive (benefit) impacts should be captured in the test.

[8] In this example, the $300 rebate would already be included in the cost-effectiveness analysis as a utility system cost.

[9] Some of these impacts may already be partially captured in utility system impacts. For example, some environmental impacts may be captured in estimates of avoided costs that capture the impact of current and/or projected future environmental regulations. Thus, to avoid double-counting, only additional "incremental" impacts should be included.

Principle #5: Forward-Looking Analyses

Analysis of the impacts of efficiency investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of efficiency measures and those that would occur absent the efficiency investments.

This principle embodies three inter-related concepts. First, cost-effectiveness analyses should only consider forward-looking impacts. Historical (or "sunk") costs should not be included when estimating the impacts of future investment decisions — they cannot be changed and will remain in place under any future scenario. Therefore, they are not relevant when comparing future investment scenarios.[10]

Historical (or "sunk") costs should not be included when estimating the impacts of future investment decisions —they cannot be changed and will remain in place under any future scenario.

Second, cost-effectiveness analyses should include long-run costs and benefits. Electric and gas resources, including many efficiency resources, can last decades. As a result, often the resource decisions made today will affect customers far into the future. Utilities have a responsibility to meet customer needs in a safe, reliable, and low-cost way over the long term. Regulators have a responsibility to protect customers over both the short term and the long term. Over-emphasis on short-term costs could unduly increase long-term costs for customers (see Chapter 11) for related discussion of analysis periods and Chapter 9 for discussion of discount rates used to analytically balance trade-offs between short-term and long-term impacts).

Third, cost-effectiveness analyses should consider only marginal impacts. These are defined as the incremental changes that will occur because of the EE resource, relative to a scenario where the resource is not in place.

Principle #6: Transparency

EE cost-effectiveness analyses require many detailed assumptions and methodologies, and they typically produce many detailed results. For regulators, other decision-makers, and other stakeholders to properly assess and understand cost-effectiveness analyses—and therefore to ultimately ensure that cost-effectiveness conclusions are reasonable and robust—key inputs, assumptions, methodologies, and results should be clearly documented in sufficient detail to enable independent reproduction of cost-effectiveness screening results. This should include all aspects of the resource assessment, including: all costs and benefits included (including all hard-to-monetize impacts); modeling parameters such as study period, treatment of risk, and discount rates; and approaches to account for additional

Results should be clearly documented in sufficient detail to enable independent reproduction of cost-effectiveness screening results.

[10] Historical costs do have important implications for rate impacts and potential cost shifting between customers. These costs should be considered in a separate rate impact analysis, as discussed in more detail in Appendix C.

considerations.[11] Such documentation should also be sufficient to replicate calculated cost-effectiveness values.

The purpose of the *Transparency Principle* is to support clear and accessible information regarding (1) the underlying jurisdiction's policies used to identify relevant impacts for inclusion in the primary test; and (2) reporting of key assumptions, results, and references from the cost-effectiveness analyses. This principle also serves as the final step in the Framework process. In Chapter 3, template tables are provided to support jurisdictions in applying this principle.

[11] Because the cost-effectiveness of EE is measured relative to the avoided costs of other resources, the assessment of those avoidable costs should be similarly transparent.

2. The Resource Value Framework and Primary Test

This chapter introduces the Resource Value Framework as a multi-step process to develop a jurisdiction's primary cost-effectiveness test – the RVT. The chapter includes an overview of the purpose of a primary test, the dynamic nature of the RVT, and its relevance to traditional cost-effectiveness tests.

2.1 Summary of Key Points

- Jurisdictions typically require a primary test to identify cost-effective efficiency resources. The Resource Value Framework is a 7-step process for jurisdictions to develop their primary cost-effectiveness test: the Resource Value Test (RVT).
- The Framework embodies the universal principles presented in Chapter 1, and in some cases discrete steps in multi-step process reflect application of a specific principle.
- While the RVT serves as a primary cost-effectiveness test, there can be value in assessing cost-effectiveness of efficiency resources from perspectives represented by other, secondary tests.
- The RVT is based upon a dynamic concept, where categories of impacts included in the test can vary across jurisdictions and/or over time because it is based on each jurisdiction's applicable policy concerns, which can vary.

2.2 The Resource Value Framework

The Framework is a series of seven steps, as shown below, that can guide any jurisdiction to develop its primary EE cost-effectiveness test. The Framework embodies the key principles described in Chapter 1, some of which represent a specific step in the framework process. Chapter 3 provides details on each of these steps.

Step 1: Identify and articulate the jurisdiction's applicable policy goals.

Step 2: Include all the utility system costs and benefits.

Step 3: Decide which non-utility impacts to include in the test, based on applicable policy goals.

Step 4: Ensure that the test is symmetrical in considering both costs and benefits.

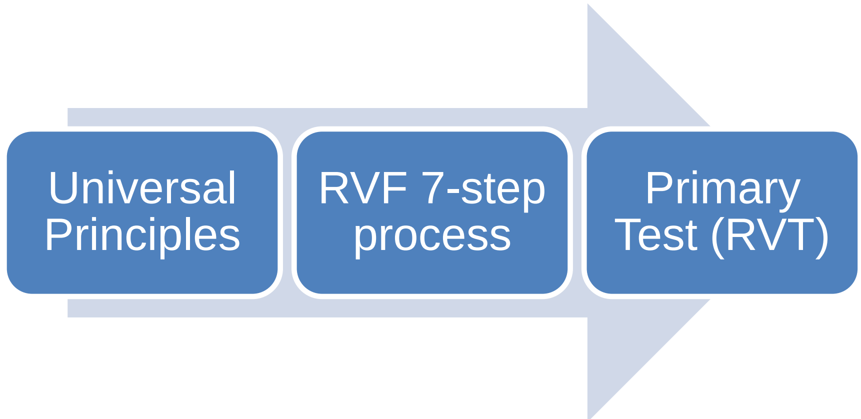
Step 5: Ensure the analysis is forward looking and incremental.

Step 6: Develop methodologies to account for all relevant impacts, including hard to quantify impacts.

Step 7: Ensure transparency in presenting the inputs and results of the cost-effectiveness test.

The relationship between the Framework, the underlying principles, and development of a primary RVT is provided in Figure 1 below and summarized further in this chapter.

Figure 1. The Foundation to Developing a Jurisdiction's Primary Test



2.3 The Resource Value Test as the Primary Test

Jurisdictions typically rely upon a primary test to identify cost-effective efficiency resources. Developing a single, primary test can be useful when comparing many different types and scenarios of efficiency resources, and it is often necessary when an efficiency resource passes one type of test, but not others.

The primary test should answer the fundamental question: *Which efficiency resources have benefits that exceed costs, where these impacts are defined by the jurisdiction's applicable policy goals*? The Resource Value Framework's underlying principles and multi-step process can support a jurisdiction's effort to answer this question, resulting in a comprehensive and transparent process that can help inform decisions on efficiency policies and practices in the jurisdiction.

The RVT serves as a primary test which assesses cost-effectiveness of efficiency resources relative to a jurisdiction's applicable policy goals that are under the purview of the jurisdiction's regulators and/or other decision-makers. However, there can be value in assessing cost-effectiveness of efficiency resources from perspectives represented by other, secondary tests.[12] Among the potential purposes of using secondary tests are:

The primary test should answer the fundamental question: *Which efficiency resources have benefits that exceed costs, where these impacts are defined by the jurisdiction's applicable policy goals*?

- To inform decisions regarding how much utility customer money could or should be invested to acquire cost-effective savings;
- To inform decisions regarding which efficiency programs to prioritize if not all cost-effective resources will be acquired;
- To inform efficiency program design; and
- To inform public debate regarding efficiency resource acquisition.

For example, the primary cost-effectiveness test is necessary but may not be sufficient for answering a second critical question: *How much utility customer funding should be*

[12] Chapter 5 provides more detail on the use of multiple cost-effectiveness tests.

spent on EE resources? This question will need to be answered by considering multiple factors such as:

- The results of the primary cost-effectiveness test;
- The results of secondary cost-effectiveness tests;
- Statutory or other requirements to implement all cost-effective EE;
- Statutory or other budget caps or constraints on efficiency resources;
- Statutory or other EE resource standards or other targets;
- Goals related to customer equity, or to providing access to all customer classes and customer types;
- Goals related to minimizing lost opportunities, or to addressing all electricity and gas end-use markets; and
- Rate, bill, and participation impacts of efficiency resources.[13]

2.4 The RVT as a Dynamic Test

The RVT reflects the impacts for which regulators/other decision-makers are responsible, including utility system impacts plus the impacts related to applicable policy goals. As such, different jurisdictions have different policy goals, and therefore they may develop different RVTs. While the RVT is conceptually a single test, in practice it might be different across jurisdictions because jurisdictions typically have a different mix of applicable policies that inform the inclusion of costs and benefits to the cost-effectiveness assessment.

The RVT is, therefore, based upon a *dynamic concept,* where categories of impacts included in the test can vary across jurisdictions and/or over time because jurisdictions' policy objectives can vary. This differs from the most common traditional tests—the UCT, TRC, and SCT—which are by associated perspectives (utility, utility plus participant, and society as a whole) *conceptually static*. The RVT can be tailored to a jurisdiction's specific interests and goals, while adhering to sound economic and public policy principles. The RVT thus provides a jurisdiction with flexibility to align with its energy and other applicable policies goals, and not be limited to the traditional tests.

> A jurisdiction's application of the Framework may result in developing a primary RVT that is the same as one of the traditional tests (UCT, TRC or SCT.) This could happen if the jurisdiction's applicable policy goals are conceptually aligned with one of those traditional tests. See Chapter 4 for examples and more details.

The dynamic nature of the RVT means that for any jurisdiction, depending on its applicable policy goals, the regulatory perspective (as described in Chapter 1) may be the same as or broader than the utility perspective. Or, it may be the same as or narrower than the societal perspective, if indeed a jurisdiction's policies reflect taking into consideration the range of all costs and benefits to society. Regulators/other decision-makers in some jurisdictions might have a relatively broad scope of responsibilities, based on their specific policy goals, while others may have a relatively narrow scope.

Chapter 3 provides detailed information on how jurisdictions can use the Framework to develop an RVT using the 7-step process. Chapter 4 provides examples of RVTs, including how they compare to common traditional cost-effectiveness tests.

[13] Appendix C provides a discussion of techniques for accounting for rate and bill impacts.

3. Developing the Resource Value Test

This chapter sets forth the detailed step-by-step process for developing a jurisdiction's primary cost-effectiveness test. The chapter ties in the principles introduced in Chapter 1, and provides template tables jurisdictions can use to support transparency in documenting cost-effectiveness analyses assumptions and results.

The Resource Value Framework's multi-step process, outlined in Figure 2 below, can be used to develop a jurisdiction's RVT as the primary cost-effectiveness test. This chapter provides guidance on each of these steps, and references relevant chapters and appendices where more detailed information is provided.

Figure 2. The Resource Value Framework Steps

STEP 1	Identify and articulate the jurisdiction's applicable policy goals.
STEP 2	Include all the utility system costs and benefits.
STEP 3	Decide which non-utility impacts to include in the test, based on applicable policy goals.
STEP 4	Ensure that the test is symmetrical in considering both costs and benefits.
STEP 5	Ensure the analysis is forward looking and incremental.
STEP 6	Develop methodologies to account for all relevant impacts, including hard to quantify impacts.
STEP 7	Ensure transparency in presenting the inputs and results of the cost-effectiveness test.

The first step is to identify and articulate the applicable policy goals of the jurisdiction. Articulating these goals at the outset of developing a framework, using a transparent process, will help ensure that the cost-effectiveness test is designed to properly account for them.

The second step is to recognize that EE is a resource that can be used to defer or avoid other energy resources, which requires that EE costs and benefits be evaluated consistently with the costs and benefits of other energy resources. As such, a cost-effectiveness test should begin by including all utility system impacts.

The *Key Principles* from Chapter 1 are embodied in the 7-step process, and in some cases, represent a discrete step.

The third step is to ensure that non-utility system impacts—both costs and benefits—associated with the jurisdiction's applicable policy goals are accounted for.

Once these first three steps are taken, then it is critical to ensure symmetry in the inclusion of the relevant impacts; to ensure the analysis is forward-looking and incremental; and to develop methods to account for all the relevant impacts. The final step is to provide transparency in presenting the inputs and results from the cost-effectiveness analysis.

3.1 STEP 1: Identify and Articulate Applicable Policy Goals

STEP 1

Review all 7 steps on page 18.

3.1.1 The Importance of Policy Goals

The first step is for a jurisdiction to identify and articulate its applicable policy goals, consistent with the *Policy Goals Principle* from Chapter 1. Documenting applicable goals at the outset of developing a test is necessary to ensure that the cost-effectiveness test explicitly and properly accounts for such goals.

Most regulators/decision-makers have broad statutory authority to: set rates that are fair, just, and reasonable; ensure that utilities and comparable entities provide customers with safe, reliable, and low-cost services; and generally guide utility actions that are in the public interest. This authority is typically defined in statutes and related regulations or other governing body decisions.

This first step of the Framework establishes a regulatory perspective, which reflects a mix of the various perspectives impacted by the jurisdiction's applicable policies.

Most regulators/decision-makers also operate in the context of other relevant policies that affect their jurisdiction, many of which are applicable to the investment of customer funds in EE resources. Table 2 (in Chapter 1) provides examples of such policies.

These goals are established in many ways, typically by statutes, regulations, orders, state energy plans, and other government directives. As emphasized earlier, these policy goals evolve over time to reflect changing conditions and governmental and public priorities.

Importantly, this first step of the Framework establishes a regulatory perspective, which reflects a mix of the various perspectives impacted by the jurisdiction's applicable policies.

3.1.2 Documenting Applicable Policy Goals

Transparency of a jurisdiction's applicable policy goals is key to helping identify the relevant costs and benefits to include a primary cost-effectiveness test. Table 3 illustrates a simplified version of how a jurisdiction could articulate its applicable policy goals. It shows how a jurisdiction's laws, regulations, orders, etc. could be documented to identify the relevance of certain policy goals to efficiency cost-effectiveness assessment. This exercise would help to provide a clear platform from which interested parties can inform and confirm priorities, gaps, or missing needs, and identify appropriate costs and benefits.

Table 3. Example Summary of a Jurisdiction's Applicable Policy Goals

Applicable Laws, Regulations, Orders, etc.	Policy Impacts Reflected in Laws, Regulations, Orders, etc.						
	Least-Cost	Fuel Diversity	Risk	Reliability	Low-Income	Environ-mental	Economic Develop-ment
PSC statutory authority	X			X			
Low-income protection	X		X	X	X		
EE or DER law or rules	X	X	X	X	X		X
State energy plan	X	X	X	X	X	X	X
Integrated resource planning	X	X	X	X	X	X	X
Renewable portfolio standard		X				X	X
Climate change		X	X			X	
Environmental protection		X	X			X	

This table is presented for illustrative purposes only, does not represent the policies of any particular jurisdiction, and is not meant to be an exhaustive list of applicable policy goals.

A more comprehensive version of the table above would ideally also:

- document the specific applicable policies;
- include a description of the relevant applicable policies;
- identify areas where policies are evolving or may evolve and should be considered; and
- identify the specific costs and benefits that should be accounted for in the test.

3.1.3 Process and Stakeholder Input

Some jurisdictions may have little experience or precedent for evaluating their applicable policy goals that are applicable to utility resource cost-effectiveness analyses. Other jurisdictions may have a long history of statutes, regulations, commission orders, and other directives that provide guidance on specific applicable policy goals. Either way, when developing a primary EE cost-effectiveness test, it is important to start with a clear articulation of all applicable policy goals.

Ideally, applicable policy goals should be assessed and articulated with a process that is transparent and open to all relevant stakeholders such as consumer advocates, low-income representatives, state agencies, efficiency representatives, environmental advocates, and others. Key stakeholders can provide important viewpoints regarding the value of EE in the context of the jurisdiction's policy goals.

This stakeholder input can be achieved through a rulemaking process, a generic jurisdiction-wide docket, commission orders on specific EE plans, working groups, technical sessions, or other approaches appropriate for the jurisdiction. The process should address objectives based on current jurisdiction policies, and should also be flexible to address new or modified polices that are adopted over time.

Some jurisdictions may wish to incorporate input from government agencies or representatives that do not typically make decisions regarding EE cost-effectiveness, but would nonetheless have insights on the jurisdiction's applicable policy goals. For example, a state's public utility commission may wish to incorporate input from that state's department of environmental protection or department of health and human services (Regulatory Assistance Project 2013a).[14]

3.2 STEP 2: Include Utility System Costs and Benefits

STEP 2

Review all 7 steps on page 18.

The second step in developing an RVT is to include the utility system impacts that will be affected by the efficiency resource. The term utility system is used here to represent the entire utility system used to provide service to retail customers. In the case of electric utilities, this includes the generation, transmission, and distribution of electricity services. In the case of gas utilities, this includes the transportation, storage, and distribution of gas services. This term refers to any type of utility ownership or management, including investor-owned utilities, publicly owned utilities, municipal utility systems, cooperatives, etc.

The utility system costs and benefits should provide the foundation for every cost-effectiveness test. This ensures that the test will, at a minimum, indicate the extent to which total utility system costs will be reduced (or increased) by the efficiency resource over a specified period. It will also indicate the extent to which average customer bills will be reduced (or increased) by the efficiency resource, because total utility system costs determine average customer bills.[15]

It is essential to ensure that avoided cost estimates are comprehensive, up-to-date, informed by stakeholders, and ultimately reviewed and approved by regulators.

Further, every cost-effectiveness test should include relevant utility system costs and benefits. In terms of costs, this should include the portion of the efficiency measure paid by the utility, other financial or technical support provided to participants, and any other utility-system costs associated with program administration and management. Regarding benefits, this should include all the utility system costs that will be avoided or deferred by implementing the EE resource.[16]

Utility system avoided costs are one of the most important inputs to any cost-effectiveness analyses of EE resources, and will significantly affect the results of the analyses. Therefore, it is essential to ensure that avoided cost estimates are

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[14] A recent statute in Michigan requires the commission to request an advisory opinion from the department of environmental quality regarding whether any potential decrease in emissions of sulfur dioxide, oxides of nitrogen, mercury, and particulate matter would reasonably be expected to result if the integrated resource plan proposed by the electric utility was approved (State of Michigan 2016).

[15] Note that the three traditional cost-effectiveness tests, the UCT, the TRC, and the SCT, all include utility system impacts, at a minimum.

[16] For the purposes of cost-effectiveness evaluation, the value of avoided utility system costs establishes the maximum amount that the utility system can contribute to a measure's costs, in order to be considered cost-effective without taking into consideration other participant and/or societal benefits and costs.

comprehensive, up-to-date, informed by stakeholders, and ultimately reviewed and approved by regulators.[17]

Including all utility system costs and benefits in any efficiency cost-effectiveness test is consistent with the *Efficiency as a Resource Principle* described in Chapter 1: that EE is a resource that should be compared with both supply-side and other demand-side energy resources in a consistent and comprehensive manner. Further, in a jurisdiction with competitive wholesale markets and distribution-only electricity utilities, it is important to account for the impacts on generation, transmission, and distribution because all these resources will be affected by the efficiency resource—even if distribution customers provide the funding of the efficiency resource.

Table 4 and Table 5 provide illustrations of the utility system costs and benefits that should be included in every cost-effectiveness test. Chapter 6 provides more detail on these utility system impacts, and Chapter 7 provides guidance on methods to develop values for these impacts.

Table 4. Example Electric Utility System Impacts to Include in Cost-Effectiveness Tests

Scope	Costs	Benefits
Utility System	Measure Costs (utility portion) Other Financial or Technical Support Program Administration Marketing and Outreach Evaluation, Measurement, and Verification Utility Performance Incentives	Avoided Energy Costs Avoided Generating Capacity Costs Avoided T&D Costs Avoided T&D Line Losses Avoided Ancillary Services Wholesale Price Suppression Effects Avoided Costs of Complying with RPS Avoided Environmental Compliance Costs Avoided Credit and Collection Costs Reduced Risk Increased Reliability

This table is presented for illustrative purposes, and is not meant to be an exhaustive list.

17 For good examples of this approach, see the New England Avoided Energy Supply Cost studies (AESC Study Group 2015); and the California Public Utility Commission cost-effectiveness calculator that embeds the state's official avoided costs in a model to calculate cost-effectiveness (CPUC 2016)

Table 5. Example Gas Utility System Impacts to Include in Cost-Effectiveness Tests

Scope	Costs	Benefits
Utility System	Measure Costs (utility portion) Other Financial or Technical Support Program Administration Marketing and Outreach Evaluation, Measurement, and Verification Utility Performance Incentives	Avoided Gas Costs Avoided Gas Pipeline Costs Avoided Gas Distribution Costs Avoided Gas Line Losses Wholesale Price Suppression Effects Avoided Environmental Compliance Costs Avoided Credit and Collection Costs Reduced Risk Increased Reliability

This table is presented for illustrative purposes, and is not meant to be an exhaustive list.

3.3 STEP 3: Decide Which Non-Utility Costs and Benefits to Include

Review all 7 steps on page 18.

The decision of which non-utility system costs and benefits to include in the RVT should build on Steps 1 and 2 of the Framework. Specifically, once a jurisdiction's applicable policies have been identified and articulated in Step 1, and utility system costs and benefits are identified to account for overarching goal to reduce electricity/gas costs and customer bills, Step 3 then involves deciding which non-utility costs and benefits to include in the test, based on applicable policy goals.

In some cases, the decision to include an impact might be straightforward. For instance, legislation establishing an EE resource standard might explicitly state that one of the goals of the standard is to promote economic development. In other cases, the decision might be less clear. For example, whether to include participant costs and benefits in the primary EE cost-effectiveness test might not be articulated anywhere (as discussed in Section 3.3). In these cases, the policy decision will need to be made by regulators and other decision-makers with appropriate input from relevant stakeholders.

Table 6 below presents a summary of commonly considered non-utility impacts that could be included in a primary test to the extent they are relevant to a jurisdiction. The table also indicates the relevant section in this chapter where each of the impacts is summarized, with more detail provided in Chapter 6 on the considerations for selecting EE costs and benefits.

In applying Step 3, regulators/ decision-makers, with input from stakeholders, can cross-reference the broad range of non-utility costs and benefits addressed in this section, and further in Chapter 6. Jurisdictions can also build on the Table 3 template (from Step 1) by adding the specific costs and benefits that apply based on the identified applicable policy goals.

Table 6. Examples of Commonly Considered Non-Utility Impacts

Non-Utility Impact	Subsection	Description
Participant impacts	3.3.1	Impacts on program participants, includes participant portion of measure cost, other fuel savings, water savings, and participant non-energy costs and benefits
Impacts on low-income customers	3.3.2	Impacts on low-income program participants that are different from or incremental to non-low-income participant impacts. Includes reduced foreclosures, reduced mobility, and poverty alleviation
Other fuel impacts	3.3.3	Impacts on fuels that are not provided by the funding utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, and wood
Water impacts	3.3.4	Impacts on water consumption and related wastewater treatment
Environmental impacts	3.3.5	Impacts associated with CO_2 emissions, criteria pollutant emissions, land use, etc. Includes only those impacts that are not included in the utility cost of compliance with environmental regulations
Public health impacts	3.3.6	Impacts on public health; includes health impacts that are not included in participant impacts or environmental impacts, and includes benefits in terms of reduced healthcare costs
Economic development and jobs	3.3.7	Impacts on economic development and jobs
Energy security	3.3.8	Reduced reliance on fuel imports from outside the state, region, or country

This table is presented for illustrative purposes, and is not meant to be an exhaustive list.

See also Step 6 in this chapter, and supporting Chapter 6, which provides information and guidance on methods for accounting for relevant costs and benefits.

3.3.1 Ensuring that Utility Customer Payments Are Justified by Customer Benefits

Regulators/decision-makers are sometimes concerned that including non-utility system impacts in the cost-effectiveness analysis could unduly burden utility customers, particularly customers who do not participate in EE programs. Regulators and consumer advocates sometimes ask: Why should electricity customers pay for participant gas or oil savings? Why should gas customers pay for participant electricity or oil savings? Why should utility customers pay for environmental, jobs, or other societal benefits?

The answer to these questions is that utility customers should pay for these benefits if called for by applicable policies in statutes, regulations, and orders, as consistent with *Policy Principle*. Presumably, the advantages of these policy benefits will outweigh the disadvantages. In many cases, such as with reliability, reduced risk, fuel diversity, economic development, energy security, and environmental benefits, all utility customers will collectively share in the non-utility system benefits.

3.3.2 Consider Participant Impacts

Efficiency program participants experience several types of costs and benefits. Program participant impacts are summarized in Table 7, and discussed in more detail in Chapters 6 and 8.

Table 7. Program Participant Costs and Benefits

Affected Party	Costs	Benefits
Efficiency Program Participant	Measure Costs (customer portion) Financial Costs (customer portion) Transaction Costs Increased O&M Costs Increased Other Fuel Consumption Increased Water Consumption	Reduced Bills (typically reflected as avoided utility system costs) Reduced O&M Costs Increased Comfort Increased Health & Safety Increased Productivity Improved Aesthetics Property Improvements Reduced Other Fuel Consumption Reduced Water Consumption Additional Benefits for Low-Income Customers

This table is presented for illustrative purposes and is not meant to be an exhaustive list. Note that some of these impacts are energy related with others are not. Those that are not energy related are conventionally referred to as non-energy costs or non-energy benefits.

When considering whether to include participant impacts in the cost-effectiveness tests, it is important to consider two overarching points:

1. The decision of whether to include participant impacts in the primary cost-effectiveness test is a policy decision. Regulators may choose to include participant impacts in the primary cost-effectiveness test if that would achieve the jurisdiction's policy goals.
2. If regulators decide to include participant costs in any cost-effectiveness test, the test must also include participant benefits, and *vice versa*. This is necessary to ensure symmetrical treatment of participant impacts, consistent with *Symmetry Principle* set forth in Chapter 1.

With regard to the first point above, some jurisdictions may not have an explicit policy goal regarding whether to include program participant impacts when assessing EE resources. Legislators and other decision-makers may not have addressed this question when promulgating legislation or regulations related to EE resources. In these cases, regulators and other decision-makers should decide whether to include participant impacts based upon the policy context that does exist in the jurisdiction and with appropriate input from relevant stakeholders.

Rationale for Including Participant Impacts

Several key issues should be addressed when deciding whether to account for participant impacts in the primary cost-effectiveness test. Regulators and other decision-makers should determine whether there is a policy justification for including participant impacts in the primary test. They should also consider the rationale and advantages of including participant impacts in the primary test.

Table 8 provides a summary of the reasons to include participant impacts in their primary cost-effectiveness test, as well counter-points to these reasons. These points and counter-points are discussed in more detail in Chapter 8.

Table 8. Points and Counter-Points Regarding Whether to Include Participant Impacts

Reasons for Including Participant Impacts	Counter-Points
Including participant impacts accounts for the costs on all utility customers: participants and non-participants.	Participant impacts fall outside the scope of utility system impacts. If EE is treated purely as a utility system resource, then participant impacts are less relevant.
Including participant impacts accounts for the total cost of the resource. If the cost of a resource is split between two entities, then it might appear to be cost-effective when it is not.	If regulators prefer to account for the total cost of a resource in order to address concerns about costs being split between two entities, it is necessary to also account for the total benefits. This objective essentially requires the use of the SCT. If this objective is important enough, jurisdictions could use an SCT as a pre-screening test and an RVT as the primary test.
Including participant impacts will help protect program participants. Excluding such costs might result in participants paying "too much" for efficiency.	Including participant impacts will not accurately capture the benefits of program participants, because in practice the primary participant benefit is typically represented in terms of avoided utility costs, not reduced customer bills. The Participant Cost test is one way to protect participants.[18] In addition, program design is the best way to protect program participants, and sound program design will result in participants being better off.
Excluding participant impacts would exclude low-income participant benefits from the analysis	Low-income participant impacts can be included in the RVT, without including all participant impacts, if justified by policy goals. Well-defined low-income programs do not require participant costs, which eliminates the typical rationale for including participant impacts.
Excluding participant impacts would exclude other fuel and water impacts from the analysis.	Other fuel and water impacts can be included in the primary test, without including all participant impacts, if justified by policy goals.

Implications for Non-Participants

Including participant impacts in the cost-effectiveness test sometimes raises concerns about how this will affect non-participants. Should all utility customers pay for non-energy benefits that are enjoyed by only participants? Will including participant impacts unduly increase the cost of EE for all customers?

Including participant impacts in the cost-effectiveness test sometimes raises concerns about how this will affect non-participants.

For those jurisdictions that choose to include participant impacts in the RVT, these concerns can be addressed through program design. The incentives offered to the EE program participant could be capped at a level equal to the utility system avoided costs. This would prevent non-participants from paying more than the benefits they receive from the EE resource. This point is also discussed in Section 3.3.1.

In addition, recall that participant non-energy benefits should be included in the RVT if participant costs are included, and vice versa—consistent with the *Symmetry Principle*.

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[18] The Participant Cost Test is described in Appendix A. As noted there, the Participant Cost Test is not well-suited for the purpose of assessing the value of EE resources. Nonetheless, it could be used as a secondary test for the purpose of protecting participants.

Those jurisdictions that do not want to support EE programs as a result of benefits that accrue only to participants could decide to exclude participant costs and benefits in the primary cost-effectiveness test.

3.3.3 Consider Low-Income Impacts

It is widely acknowledged that efficiency programs serving low-income customers and low-income communities provide important benefits beyond utility system impacts. Table 9 presents a summary of the types of low-income impacts beyond utility system impacts.

Table 9. Non-Utility Low-Income Costs and Benefits

Affected Party	Costs	Benefits
Efficiency Program Participant	Typically, none. Well-designed low-income programs cover all costs and remove all barriers to low-income customers.	Reduced energy burden Reduced O&M costs Increased comfort Increased health & safety/reduced medical costs Increased productivity Improved aesthetics Property improvements Reduced home foreclosures Reduced need to move/relocate due to unpaid bills
Society	Typically, none.	Alleviating poverty Improving low-income community strength and resiliency Reduced home foreclosures

This table is presented for illustrative purposes, and is not meant to be an exhaustive list.

Many of the benefits to low-income participants accrue to non-low-income efficiency program participants as well. However, the magnitude of some of these benefits can be greater in low-income homes, because (a) the pre-program condition of low-income housing can be worse than that of non-low-income housing, and (b) because the financial condition of low-income customers often more significantly constrains how they manage and live in their homes.

As indicated in Table 9 some low-income benefits affect low-income program participants while some affect society in general. Other low-income benefits, such as reduced foreclosures, could be characterized as accruing to both the participant and society.

Jurisdictions that have policy goals requiring or encouraging the protection of low-income customers should include low-income impacts in their RVT. It is not necessary to include all participant impacts in the RVT in order to include low-income impacts.

> The Colorado PUC requires Public Service Company of Colorado to account for low-income benefits by increasing avoided costs with a 25% proxy multiplier (Skumatz 2014).

Regulators and other decision-makers who choose to include low-income benefits in the RVT do not need to distinguish between benefits to the participant versus those to society. In both cases, the low-income benefits fall outside the scope of utility system impacts, and in both cases these benefits can be included in the primary test, as identified by the jurisdiction's applicable policies.

As noted earlier, some jurisdictions may not have explicit statutes or regulations that address whether low-income impacts should be included in EE cost-effectiveness analyses. In these instances, regulators should develop a policy on how to address low-income impacts; ideally with stakeholder input and due process.

3.3.4 Consider Other Fuel Impacts

Some efficiency resources can either reduce or increase the consumption of "other fuels," which includes fuels beyond those provided by the utility funding the efficiency resource. Other fuels can include savings or increased use of gas (for an electric utility funding the efficiency resource), electricity (for a gas utility funding the efficiency resources), oil, propane, biomass, or other fuels used in a home or business. Table 10 presents several examples of where other fuel impacts can occur in efficiency programs. Further detail on Other Fuels is provided Chapter 6.

Table 10. Examples of Other Fuel Impacts in Efficiency Programs

Program Option	Description
Multi-fuel measures	When efficiency measures for one type of fuel result in savings of another type; for example, when insulation is installed in buildings that are cooled with electric air conditioning but heated with other types of fuels. Multi-fuel efficiency measures are frequently used in building retrofit programs and in new construction programs.
Fuel-optimization measures	When customers can choose from multiple fuel types to optimize the efficiency of an end-use. For example, customers may be given the option to switch from an inefficient oil heating system to a high-efficiency gas heating system.
Fuel-neutral programs	When regulators and efficiency planners choose to offer whole-building efficiency programs that address all fuel types with a single program provided by a single program administrator. This results in more efficient program delivery, fewer transaction costs, greater efficiency measure adoption, and better customer service in general.
Combined heat and power programs	When technologies are used to generate electricity efficiently, but require increased consumption in other fuels such as natural gas or biomass.
Strategic electrification options	When programs are designed to promote switching from non-electric to electric fuel for policy reasons. For example, an electric utility may wish to promote electric vehicles to achieve environmental and transportation policy goals.

Some efficiency programs might include more than one of the program options listed above. For example, fuel-neutral programs typically include multi-fuel measures and can include fuel-optimization measures.

Jurisdictions that have policy goals promoting the efficient use of other fuels should include other fuel impacts in their RVT. This would be appropriate for jurisdictions with goals relating to multi-fuel measures, fuel-optimization measures, fuel-neutral programs, combined heat and power programs, or strategic electrification programs.

As described in Appendix C, it is not necessary to include participant impacts in the RVT in order to include other fuel impacts. Whenever other fuel impacts are included in a cost-effectiveness test it is important to ensure that the test properly accounts for both reductions and increases in the other fuels.

Illinois law requires that electric EE cost effectiveness testing account for quantifiable societal benefits, including avoided natural gas utility costs, and that natural gas EE cost-effectiveness considers other quantifiable societal benefits, including avoided electric utility costs (Illinois 2009).

3.3.5 Consider Water Impacts

Some efficiency measures affect the consumption of water resources, where efficiency can reduce water consumption and wastewater costs by making certain end-uses, such as water heaters, dish washers, or clothes washers, more efficient. EE measures can also reduce water consumption and wastewater costs by reducing the need for electricity generation from power plants that consume water (Regulatory Assistance Project 2013c). Further detail on water impacts is provided in Chapter 6.

Jurisdictions whose applicable policy goals require or encourage the reduction in water and wastewater resources should include these impacts in their RVT. It is not necessary to include participant impacts in the RVT in order to include water impacts. Either way, care should be taken to ensure there is no overlap in participant, utility, or societal water savings. Whenever these resources are included in a cost-effectiveness test it is important to ensure that both reductions and increases in water and wastewater resources are accounted for properly.

The Oregon Commission has determined that efficiency cost-effectiveness analyses should include total costs and total benefits, including quantifiable non-energy benefits, which should encompass water savings (Oregon 1994).

3.3.6 Consider Environmental Impacts

Efficiency resources can provide a variety of benefits by reducing the environmental impacts of the energy resources that are avoided or deferred. Table 11 summarizes some of these key environmental benefits. In some cases, efficiency programs might cause environmental costs, which must be accounted for along with environmental benefits. Further detail on environmental impacts is provided in Chapter 6.

Table 11. Examples of Environmental Impacts of EE Resources

Types of Environmental Impacts
• Reduced carbon emissions • Reduced emissions of criteria and other air pollutants • Reduced liquid and solid waste (nuclear, coal ash, etc.) • Reduced water for cooling electric generating stations, extracting natural gas (e.g., “fracking”), and other purposes • Reduced adverse impacts on the land that must be developed for new generating facilities • Reduced adverse impacts on land, air, and water from fuel mining or extraction

This table is presented for illustrative purposes and is not meant to be an exhaustive list. These environmental impacts can be in the form of costs or benefits. For each type of environmental impact included in the RVT, both costs and benefits, should be included.

The costs of complying with current and future environmental regulations should be included in the utility system costs. Only additional environmental impacts that might occur despite compliance with environmental regulations (i.e., residual impacts), should be considered a non-utility system impact. Regulators and efficiency planners should treat these two types of environmental impacts separately, to avoid double-counting.

Jurisdictions that have applicable policy goals requiring or encouraging the reduction of environmental impacts should include environmental impacts in their RVT.

3.3.7 Consider Public Health Impacts

> District of Colombia law requires that in "supervising and regulating utility or energy companies, the Commission shall consider the *public safety,* the economy of the District, the conservation of natural resources, and the preservation of environmental quality" (District of Columbia 2008).

One of the results of some of the environmental emission and waste reductions discussed above is a reduction in the frequency and/or severity of health problems of populations impacted by fuel extraction and combustion. Such reductions can reduce the level of societal investment required in medical facility infrastructure, as well as in the health, well-being, and economic productivity of the populace.

Public health benefits can take the form of direct benefits in health of the populace caused by reduced air emissions from power plant generation due to EE investments. Health issues typically considered here include those associated with poor air quality due to ozone or smog, such as respiratory problems and asthma. Public health benefits can also take the form of indirect benefits from reduced healthcare costs for customers.

In addition to improved *outdoor* air quality and associated public health impacts, EE investments in buildings can improve the health of occupants by addressing and improving *indoor* air quality (IAQ), largely through improved building envelope and ventilation measures. While direct health impacts to home occupants, especially related to reduced asthma incidences, are relevant to participant impacts (as addressed above), there are also important broader public health impacts associated with reduced emergency room visits, and associated medical costs.

Jurisdictions whose applicable policy goals include improving public health should include public health impacts in their RVT. Jurisdictions that choose to include participant, environmental, and public health impacts should ensure that there is no double-counting across these three types of impacts.

> Rhode Island law establishes state greenhouse gas reduction goals, and articulates that "consideration of the impacts of climate change shall be deemed to be within the powers and duties of all state departments, agencies, commissions, councils, and instrumentalities..." (Rhode Island 2014).

3.3.8 Consider Economic Development and Job Impacts

All types of utility resource investments will have economic development and job impacts. EE resources will typically increase jobs and economic development, relative to investments in supply-side resources. The types of jobs associated with EE generally fall into three categories:

- Jobs associated with managing, delivering, and evaluating the efficiency programs.
- Jobs associated with additional work and revenue that EE programs funnel to the supply chains associated with efficiency measures being installed in homes and

businesses; this includes contractors, builders/developers, equipment vendors, product retailers, distributors, manufacturers, and others (E4TheFuture 2016b, 4).

- Indirect impacts, where customers with reduced energy bills will have more disposable income that may be spent in the local community (or beyond), which helps create jobs and spur economic development.

Jurisdictions whose applicable policy goals include promoting jobs and economic development should include these impacts in their RVT. When this is done, it is necessary to also account for jobs lost or reduced economic development. In other words, the cost-effectiveness analysis should include *net* economic and job impacts from the efficiency program.

> Delaware's Energy Conservation and Efficiency Act states that the benefits of cost-effective EE include new economic development opportunities (Delaware 2009).

3.3.9 Consider Energy Security

EE can reduce the consumption of fuels and resources that are imported from outside the relevant jurisdiction. This can include fossil fuels that are imported from other regions, electricity that is imported by transmission lines, and natural gas that is imported through pipelines. It can also include fossil fuels that are imported from other parts of the world, including countries that are politically or economically unstable. Over-reliance upon imported fuels can increase price volatility and increase risks associated with energy supply and reliability.

> A Washington statute states that "increasing energy conservation and the use of appropriately sited renewable energy facilities will promote energy independence in the state and the Pacific Northwest region (Washington 2006).

Jurisdictions whose applicable policy goals include promoting energy security should include these impacts in their RVT. When this is done, it is necessary to ensure that there is no double-counting of this impact in other impacts, such as utility-system risk impacts and jobs and economic development impacts.

3.4 STEP 4: Ensure the Test Is Symmetrical

Review all 7 steps on page 18.

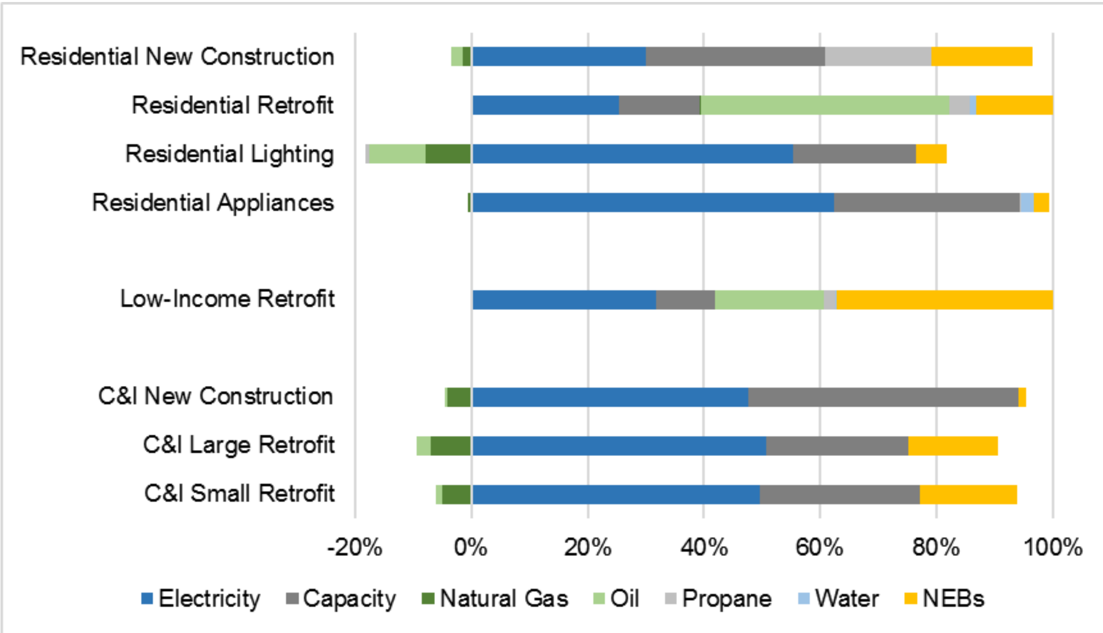
Once it has been determined what categories of impacts to include in a jurisdiction's RVT in Step 3, Step 4 is to ensure that the test includes all costs and all benefits associated with each category of impacts. If some costs are excluded, the framework will be inappropriately biased in favor of efficiency; if some benefits are excluded, the framework will be inappropriately biased against efficiency. If the test results in a bias either in favor of or against EE resources, the result will be a misallocation of resources, with higher than necessary costs incurred by utility customers. Hence the importance of applying the *Symmetry Principle* as a discrete step in the Framework process.

> **If the test results in a bias either in favor of or against EE resources, the result will be a misallocation of resources, with higher than necessary costs incurred by utility customers.**

One example of where this is especially important is regarding program participant costs and benefits. Where states have used the TRC test, which should include participant *costs*, most states do not in reality include participant *benefits* (ACEEE 2012).[19] This leads to a cost-effectiveness test that is skewed against EE. The results will understate the benefits of efficiency resources, and lead to higher utility costs than necessary (Regulatory Assistance Project 2012).

Figure 3 presents the percent of total benefits that are created by different types of benefits, including participant NEBs, using the results of cost-effectiveness analyses for actual efficiency programs operated by a Massachusetts electric utility (Eversource 2017). As indicated, participant NEBs can represent a large portion of total benefits, and will significantly affect the cost-effectiveness results.

Figure 3. Implications of Participant Benefits on Residential Efficiency Programs



Finally, applying the principle of symmetry sometimes requires estimating "net" impacts for certain types of benefits. For example, if economic development gains from EE resources are included in the cost-effectiveness framework, it is important to also include economic development losses associated with not implementing the avoided resources in the counter-factual scenario. This is frequently achieved by estimating net economic development gains from efficiency resources.

3.5 STEP 5: Ensure the Analysis Is Forward-Looking and Incremental

Review all 7 steps on page 18.

Step 5 applies the *Forward-Looking Principle,* which requires that cost-effectiveness analyses should be forward-looking and incremental. This requires accounting for future, long-run, marginal costs and benefits, which embodies three inter-related concepts.

[19] Throughout this discussion, the term "participant benefits" refers to all of the benefits other than the reduction in the participant's utility bill.

1) Cost-effectiveness analyses should only consider forward-looking impacts. Historical (or “sunk”) costs should not be included when estimating the impacts of future investment decisions. Historical costs cannot be changed, and will remain in place under any future scenario, and therefore are not relevant when comparing future investment scenarios.[20]

2) Cost-effectiveness analyses should include long-run costs and benefits. Electric and gas resources can last for forty or even sixty years. Thus, the resource decisions made today will affect customers for decades in the future. Utilities have a responsibility to meet customer needs in a safe, reliable, and low-cost way over the long term. Regulators have a responsibility to protect customers over both the short term and the long term. Over-emphasis on short-term costs could unduly increase long-term costs for customers.[21]

3) Cost-effectiveness analyses should consider only marginal impacts. These are defined as the incremental changes that will occur because of the EE resource, relative to a scenario where the resource is not in place.

3.6 STEP 6: Develop Methodologies to Account for All Relevant Impacts

Review all 7 steps on page 18.

Step 6 applies the *All Relevant Impacts Principle.* This requires that all relevant impacts of EE resources that a jurisdiction has chosen to assess via its cost-effectiveness test should ideally be estimated in monetary terms. In this way, they can be readily compiled and compared directly. However, some EE impacts are difficult to quantify in monetary terms, either due to the nature of the impact or the lack of information available about the impacts.

Substantive EE resource costs and benefits should not be excluded or ignored because they are difficult to quantify and monetize. Approximating hard-to- quantify impacts is preferable to assuming that those substantive costs and benefits do not exist or have no value.

Table 12 summarizes five different approaches that can be used to account for all impacts of EE resources that a jurisdiction has chosen to include in its cost-effectiveness test. The approaches are listed in order of technical rigor and preference.

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[20] Historical costs do have important implications for rate impacts and potential cost-shifting between customers. These costs should be considered in a separate rate impact analysis, as discussed in more detail in Appendix C.

[21] Discount rates are used to enable the regulators to properly balance short-term and long-term impacts on customers. This topic is addressed in Chapter 9.

Table 12. Different Approaches to Account for All Relevant Impacts

Approach	Description
Jurisdiction-specific studies	Jurisdiction-specific studies on EE costs and avoided cost offer the best approach for estimating and monetizing relevant impacts.
Studies from other jurisdictions	If jurisdiction-specific studies are not available; studies from other jurisdictions or regions, as well as national studies, can be used for estimating and monetizing relevant impacts.
Proxies	If monetized impacts are not available; well-informed and well-designed proxies can be used as a simple substitute.
Quantitative and qualitative information	Relevant quantitative and qualitative information can be used to consider impacts that cannot or should not be monetized.
Alternative thresholds	Pre-determined thresholds that are different from one (1.0) can be used as a simplistic way to account for relevant impacts that are not otherwise accounted for.

3.7 STEP 7: Ensure Transparency

Review all 7 steps on page 18.

The *Transparency Principle* provided in Chapter 1 constitutes a discrete and final step in the Resource Value Framework process. Transparency is critical to supporting a successful RVT. EE cost-effectiveness analyses require many detailed assumptions and methodologies, and they typically produce many detailed results.

There are two key junctures where transparency is addressed in this NSPM. The first is addressed as part of Step 1 earlier in Chapter 3.1, which includes a template format (Table 3) for how a jurisdiction could articulate its energy and other applicable policy goals. This exercise can help to provide a clear platform from which interested parties can confirm priorities, gaps or missing needs, and identify appropriate costs and benefits.

The second juncture for providing transparency is with regard to documenting the inputs, assumptions, and results of the cost-effectiveness analyses. A reporting template can be used to provide clear and consistent information for all interested parties. If used across jurisdictions, this template can provide comparability across cost-effectiveness assumptions and results to support sharing of data, where appropriate, and identification of possible opportunities for improvements in program design.

Why Transparency? In order for regulators and other stakeholders to properly assess and understand cost-effectiveness analyses—and therefore to ultimately ensure that cost-effectiveness conclusions are reasonable and robust—key inputs, assumptions, methodologies and results should be clearly documented in sufficient detail to enable independent reproduction of cost-effectiveness screening results.

3.7.1 Template Reporting Table

As a jurisdiction applies the Resource Value Framework to develop its cost-effectiveness test, transparent documentation of all key inputs, assumptions, methodologies, and results will help ensure that the approach to cost-effectiveness analysis is consistent with fundamental economic principles. It will also help to support stakeholder discussions and input to regulatory and other policymaker considerations and decisions.

The use of a standard template will help to provide a comprehensive, consistent, and easily accessible structure for such documentation. The template should present both the monetized and non-monetized findings of the assessment. It should include references for all key assumptions and methodologies used. The scope of reporting can be at the program, sector, or portfolio level. The sample template is provided in Table 13 below.

Table 13. Efficiency Cost-Effectiveness Reporting Template

Program/Sector/Portfolio Name:		Date:	
A. Monetized Utility System Costs		**B. Monetized Utility System Benefits**	
Measure Costs (utility portion)		Avoided Energy Costs	
Other Financial or Technical Support Costs		Avoided Generating Capacity Costs	
Program Administration Costs		Avoided T&D Capacity Costs	
Evaluation, Measurement, & Verification		Avoided T&D Line Losses	
Shareholder Incentive Costs		Energy Price Suppression Effects	
		Avoided Costs of Complying with RPS	
		Avoided Environmental Compliance Costs	
		Avoided Bad Debt, Arrearages, etc.	
		Reduced Risk	
Sub-Total Utility System Costs		**Sub-Total Utility System Benefits**	
C. Monetized Non-Utility Costs		**D. Monetized Non-Utility Benefits**	
Participant Costs	*Include to the extent these impacts are part of the RVT.*	Participant Benefits	*Include to the extent these impacts are part of the RVT.*
Low-Income Customer Costs		Low-Income Customer Benefits	
Other Fuel Costs		Other Fuel Benefits	
Water and Other Resource Costs		Water and Other Resource Benefits	
Environmental Costs		Environmental Benefits	
Public Health Costs		Public Health Benefits	
Economic Development and Job Costs		Economic Development and Job Benefits	
Energy Security Costs		Energy Security Benefits	
Sub-Total Non-Utility Costs		**Sub-Total Non-Utility Benefits**	
E. Total Monetized Costs and Benefits			
Total Costs (PV$)		**Total Benefits (PV$)**	
Benefit-Cost Ratio		**Net Benefits (PV$)**	
F. Non-Monetized Considerations			
Economic Development and Job Impacts	*Quantitative information, and discussion of how considered*		
Market Transformation Impacts	*Qualitative considerations, and discussion of how considered*		
Other Non-Monetized Impacts	*Quantitative information, qualitative considerations, and how considered*		
Determination:	**Do Efficiency Resource Benefits Exceed Costs? [Yes / No]**		

Note that the most useful and appropriate way to present the results of analyses of monetized efficiency costs and benefits is in present value (PV$) terms. Present value is defined as the value today (or a given year) of a certain amount of money in the future, where the future value is converted to PV$ using a discount rate. (See Chapter 9 for discussion of discount rates).

In addition, the PV$ values should cover the full life of the resource being analyzed (see Chapter 11 for discussion of analysis periods), or what is sometimes referred to as the cumulative present value or the present value of lifecycle costs and benefits. A cumulative or lifecycle present value is the discounted sum of a stream of current and future annual costs and benefits.

3.7.2 Reporting Categories and Descriptions

The key reporting categories in Table 13, and supporting descriptions, are as follows:

- **Monetized Utility System Costs and Benefits.** Sections A-B of the template table report on the utility system impacts, the foundation of any cost-effectiveness analysis, consistent with the *Efficiency as a Resource Principle*. More detailed information on the sub-categories of utility system costs and benefits can be found in Chapter 6 of this manual.
- **Monetized Non-Utility Costs and Benefits.** Sections C-D of the template table report on the non-utility impacts, as identified and informed by the Framework Steps 1-6. Consistent with the *Symmetry Principle* for treatment of costs and benefits, for any category of costs included on the left side of the template in Table 13 (Section C) there should also be corresponding benefits included on the right side of the table (Section D)—and vice versa. More detailed information on the sub-categories of non-utility system costs and benefits can be found in Chapter 6 of this manual. A discussion of methodologies for monetizing impacts can be found in Chapter 7.
- **Benefit-Cost Ratios and Net Benefits.** Section E of the template table includes several reporting parameters that provide critical information regarding cost-effectiveness test results:
- **Total Costs (PV$) and Total Benefits (PV$)** are simply the sum of all monetized utility system and non-utility costs and benefits.
- **Benefit-Cost Ratio** is equal to the ratio of the cumulative present value of benefits to the cumulative present value of costs. This metric is especially useful as a simple benchmark for determining cost-effectiveness: if an efficiency resource's BCR exceeds 1.0, it means that benefits exceed costs. That criterion is typically used to indicate that something is cost-effective.

  The BCR metric can be useful for comparing efficiency resources with each other (i.e., a higher BCR indicates one resource is "more cost-effective" than another), because it effectively normalizes the results for programs of different sizes. This metric is also useful for comparing efficiency resources across utilities and jurisdictions of different sizes, again because it effectively normalizes the results for any differences in size.[22]

The BCR metric provides an important element of information that is not provided by a net benefits metric. It does this by indicating the relative effectiveness of the money spent on the resource. i.e., how many dollars of benefits are received per dollar spent. For example, a net benefit of $10 million in PV$ does not indicate how much money was needed to generate those net benefits. It could have cost $90 million, with benefits of $100 million and a BCR of 1.11. Or it could have cost $4 million, with benefits of $14 million and a BCR of 3.50.[23]

- **Net Benefits (PV$)** is equal to the difference between the cumulative present value of benefits and the cumulative present value of costs. This metric is useful as a benchmark for determining cost-effectiveness: if an efficiency resource's net benefits are greater than zero, it should be deemed to be cost-effective.

  The net benefits metric provides an important element of information that is not provided by the BCR metric, by indicating the absolute magnitude of the benefits to be gained by the efficiency resource. For example, a BCR of 2.2 does not indicate how much money will be saved by the resource. It might save $1 million, $10 million, or $100 million.

  The net benefits of efficiency resources cannot easily be used to compare efficiency resources across different utilities and jurisdictions. A large utility would naturally expect to have higher net benefits than a small utility for a comparable type of program.

- **Non-Monetized Considerations.** Section F of the template shown in Table 13 is where discussion of the non-monetized impacts should be summarized. See Chapter 7 for discussion of techniques for consideration of non-monetized impacts.

[22] However, in making such comparisons it is important to recognize that different utilities and jurisdictions might have different avoided costs, i.e., different benefits for the same amount of savings. Different jurisdictions might also include different impacts in their resource assessment test.

[23] On the other hand, trying to maximize the BCR by including only measures/programs with the highest BCRs can result in excluding resources that are still cost-effective and would contribute to greater net benefits. This is sometimes referred to as "cream-skimming."

4. Relationship to Traditional Tests

This chapter provides examples of the RVT for a hypothetical set of jurisdictions, emphasizes the variable nature of the RVT, and discusses its relationship with the cost-effectiveness tests that have traditionally been most commonly used (the UCT, TRC and SCT).

4.1 Summary of Key Points

- Because the RVT is based on each jurisdiction's policy objectives, and those objectives can vary across jurisdictions, it can—indeed, it should—take a variety of different forms across different jurisdictions.
- Among the forms the RVT can potentially take are the conceptual forms of the three traditional used tests: the UCT, TRC test, or the SCT. The RVT will align with one of those tests only if the jurisdiction's policy objectives are (1) limited to just minimizing utility system costs (UCT); (2) concerned with minimizing the combination of utility system costs, other fuel costs, and efficiency program participant costs—but with no other impacts (TRC); or (3) concerned with all potential societal impacts (SCT).
- However, in most jurisdictions, the mix of relevant policy objectives will lead to an RVT that is different in at least some respects from the conceptual construct of each of the traditional tests.
- Many jurisdictions that have been nominally using one of the traditional tests have actually modified the tests—adding or subtracting categories of impacts—to the point where they are fundamentally different from the conceptual construct of such tests. In effect, those jurisdictions have attempted to do what the Resource Value Framework is designed to do: develop a test that aligns with their policy objectives. However, because such efforts are not always as systematic, transparent, or grounded in key principles of cost-effectiveness as they could be, the resulting tests can be less effective in addressing jurisdictional policy objectives than if an RVT was developed using the framework put forward in this manual.

4.2 Resource Value Test Examples

As explained in Chapters 1–3, using the Framework process leads a jurisdiction to develop a primary RVT that is specific to each jurisdiction, based on its applicable policy objectives. Thus, RVTs can and should take a variety of different forms across different jurisdictions. Among the forms an RVT could potentially take are the conceptual forms of the traditional tests: the UCT, the TRC test, and the SCT.

Alternatively, a jurisdiction's RVT can take—and probably often will take—a form that is different from the conceptual construct of the traditional tests.

Alternatively, a jurisdiction's RVT can take—and probably often will take—a form that is different from the conceptual construct of the traditional tests. The extent to which a jurisdiction's RVT diverges from or aligns with the traditional tests will be a function of the jurisdiction's relevant policy objectives.

This is shown for six hypothetical jurisdictions described in the bullets below and summarized in Table 14. For illustrative purposes, the six jurisdictions are split into two groups. First, in hypothetical jurisdictions 1 through 3, the application of the Resource Value Framework leads to development of an RVT that differs from the traditional cost-effectiveness tests. Second, in hypothetical jurisdictions 4 through 6, the application of Framework leads the jurisdiction to the development of an RVT or primary test where the impacts included are consistent with what should be included in the traditional cost-effectiveness tests, in their conceptual form.

Table 14. Mix of Policy Objectives Leading to Different Jurisdictional RVTs

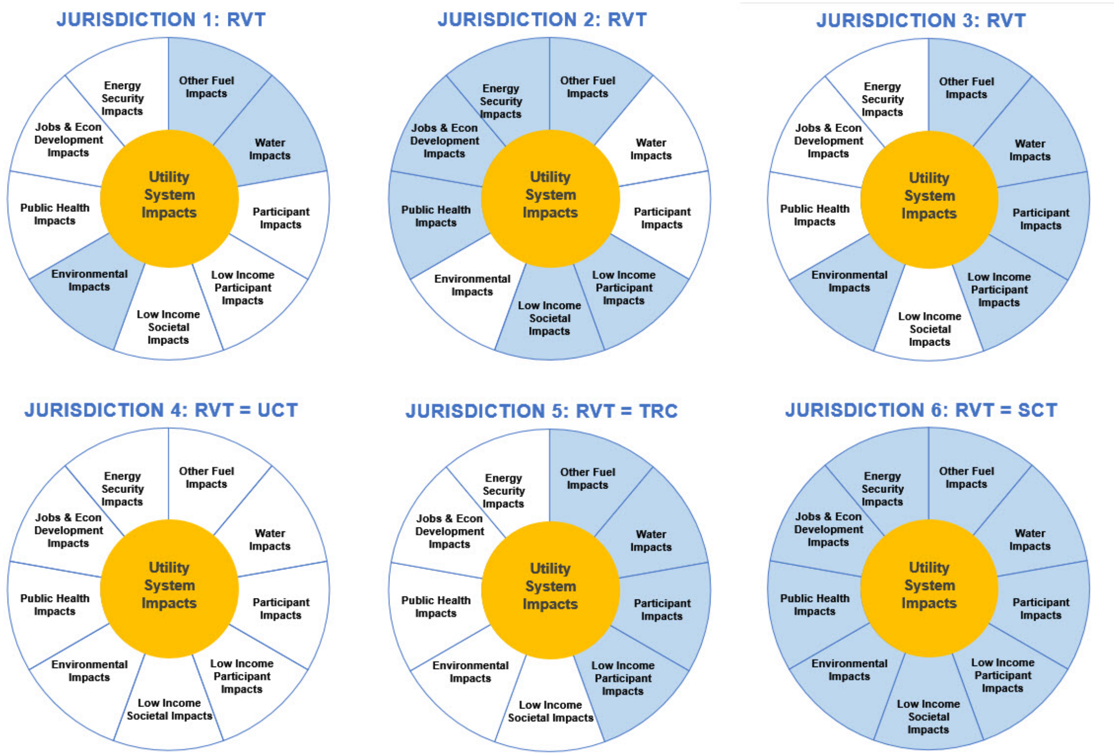
Impacts	Jurisdiction					
	1	2	3	4	5	6
	RVTs Differ from Any Traditional Test			RVT = UCT	RVT = TRC	RVT = SCT
Utility System	✓	✓	✓	✓	✓	✓
Other Fuels	✓	✓	✓		✓	✓
Water	✓		✓		✓	✓
Participants			✓		✓	✓
Low-Income Participants		✓	✓		✓	✓
Low-Income Societal		✓				✓
Environmental	✓		✓			✓
Public Health		✓				✓
Economic Development		✓				✓
Energy Security		✓				✓

- **Jurisdiction #1** is interested in not just minimizing utility system costs, but also with minimizing total energy costs (i.e., across all fuels), minimizing water costs, and minimizing environmental costs. Because it is concerned with more than utility system costs, its RVT is not the same as the UCT. Because it is not concerned with participant costs but is concerned with environmental costs, its RVT is not the same as the TRC. And because it is not concerned with either participant costs or a range of other impacts (other than the environment), its RVT is not the same as the SCT.
- **Jurisdiction #2** represents a jurisdiction that is interested in utility system impacts, other fuel impacts, low-income impacts, public health impacts, economic development impacts, and energy security impacts. Again, that mix of concerns is not the same as the mix represented by either the UCT, TRC, or SCT.
- **Jurisdiction #3** is interested in utility system, other fuel, water, participant, low-income participant, and environmental impacts. That mix of concerns is clearly much more than those captured by the UCT or TRC and less than those captured by a strict application of the SCT. In short, it is somewhere “between” the TRC and SCT.
- **Jurisdiction #4** determines that its only policy interest related to efficiency investments is in minimizing costs to the funding utility system, producing an RVT that is conceptually identical to the UCT.

- **Jurisdiction #5** determines that its policy interests are limited to impacts on the utility system plus impacts on other fuels, water, and EE program participants (low-income and non-low-income). Therefore, its RVT is conceptually consistent with the TRC.[24]
- **Jurisdiction #6** determines that its policy interest extends to all utility, other fuel, water, participant, low-income, environmental, public health, economic development, energy security, and any another relevant non-utility impacts, producing an RVT that is conceptually identical to the SCT.[25]

These six scenarios are also illustrated graphically in Figure 4. The graphics for Jurisdictions 1, 2 and 3 show that the applicable policies for these jurisdictions would lead these jurisdictions to an RVT that differs from any one of the traditional cost-effectiveness tests. While for Jurisdictions 4, 5 and 6, the applicable policies would lead these jurisdictions to developing a primary test that aligns with the traditional UCT, TRC, and SCT, respectively.

Figure 4. Mix of Policy Objectives that Lead to a Jurisdictional RVT Identical to a Traditional Test



24 The phrase "conceptually consistent with the TRC" is used because the concept underlying the TRC is consideration of utility system plus participant impacts. As discussed further in Appendix A, the application of the TRC in most jurisdictions has historically often not been consistent with that concept because most jurisdictions that use the TRC include all participant costs but only a portion of or even no participant non-energy benefits, violating the symmetry principle described in Chapter 1 of this manual.

25 The phrase "conceptually identical to the SCT" is used because the concept underlying the SCT is consideration of all utility, other resource, participant, and societal impacts. As discussed further in Appendix A, the application of the SCT in most jurisdictions is not consistent with that concept because most jurisdictions that use the SCT (1) include all participant costs but only a portion of or even no participant non-energy benefits and (2) do not fully account for all societal impacts.

Note: The size of the "pie pieces" in these graphs is not intended to convey any sense of relative magnitude or importance of the different categories of benefits.

4.3 Conceptual Differences between the RVT and Traditional Tests

Conceptually, each of the three traditional tests represents a different perspective on cost-effectiveness: the perspective of the utility system (UCT), the combined perspective of the utility system plus efficiency program participants (TRC), and the societal perspective (SCT). Thus, each addresses a fundamentally different cost-effectiveness question and includes a different set of costs and benefits. A more detailed discussion of these tests is included in Appendix A.

The new test put forward in this manual—the RVT—represents a different perspective: minimizing costs in the context of a jurisdiction's applicable policy goals. As Table 15 shows, analysis from that perspective answers a conceptually different cost-effectiveness question than any of the three questions answered by the traditional tests: will utility system costs be reduced while achieving relevant policy goals? As discussed in Section 4.2, depending on the energy policies of a jurisdiction, that may or may not lead to inclusion of different categories of impacts (costs and benefits) in the test. The conceptual differences between the RVT and the three traditional tests are summarized in Table 15.

Table 15. Comparing the RVT and the Traditional Tests

Test	Perspective	Key Question Answered	Categories of Costs and Benefits Included
Utility Cost Test	The utility system	Will utility system costs be reduced?	Includes the costs and benefits experienced by the utility system
Total Resource Cost Test	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the costs and benefits experienced by society as a whole
Resource Value Test	Regulators or decision-makers	Will utility system costs be reduced, while achieving applicable policy goals?	Includes the utility system costs and benefits, plus those costs and benefits associated with achieving energy policy goals

In those cases where a jurisdiction's policy goals align with one of the other tests, the RVT will be the same as that other test.

Importantly, the RVT is conceptually dynamic rather than static, i.e., it can include different types of impacts in different jurisdictions because policy objectives can vary across jurisdictions. And within any given jurisdiction, the components of the RVT can evolve over time as policies change. In contrast, the categories of impacts included in the traditional tests—UCT, TRC, and SCT—are conceptually fixed. They would not change (either across jurisdictions or over time) if the tests were applied in their purest conceptual form (as shown in Figure 5 for example.)

That said, in reality many jurisdictions have used and/or are currently using tests that go by the name of one of the traditional tests, but are fundamentally different from the conceptual construct of those tests. Examples include:

- States that nominally use the TRC, but exclude other fuel impacts and/or exclude participant non-energy benefits even though such impacts would need to be included to represent the conceptual construct of the TRC—i.e., cost-effectiveness from the combined perspective of the utility system and efficiency program participants;
- States that nominally use the TRC, but include environmental or other impacts that are beyond the conceptual scope of the TRC; and
- States that nominally use the SCT, but do not include any societal impacts other than environmental impacts—i.e., falling short of a true societal perspective.

The Regulatory Perspective flows from the notion that it cannot be determined whether a resource has benefits that exceed its costs without first being clear about what goals the resource investment decisions should accomplish.

In effect, some jurisdictions appear to have been doing or trying to do what the RVT is explicitly designed to do: developing a test that aligns with their policy objectives. However, rather than systematically building such a test from the ground up using the Framework described in this manual, decision-makers started with one of the traditional tests and then added categories of impacts that were construed to be important to add, and/or subtracted categories of impacts that were not considered important enough to include. Such a process could potentially lead to the very same test that the application of the Resource Value Framework would produce.[26]

However, such a piecemeal approach suffers from several drawbacks. First, the process is not likely to be initially grounded in the key principles of cost-effectiveness analysis enunciated in this manual. Second, it begins with a traditional test, which may not be the best starting point and whose economic implications may not be fully understood. Third, the consideration of policy objectives may not be systematic or sufficiently thorough. As a result, such a process can lead to a test that does not fully align with the jurisdiction's policy objectives or other cost-effectiveness fundamentals. Finally, the process for arriving at the test may not be transparent enough to enable an adequate level of understanding and informed input by stakeholders. For these multiple reasons, the use of the Framework to develop a jurisdiction-specific cost-effectiveness test is the recommended approach.

In reality, many jurisdictions have used and/or are currently using tests that go by the name of one of the traditional tests, but are fundamentally different from the conceptual construct of those tests.

[26] The California Public Utility Commission Staff recently proposed a new cost-effectiveness test for DERs that is generally consistent with an RVT (California Public Utility Commission Staff 2017). The Staff proposes to use a test that includes utility system impacts, participant impacts, and specific environmental impacts. California has been using the TRC test for many years, and the environmental impacts were added based on legislative directives. While the Staff proposal refers to its new test as an SCT, it does not include all societal impacts. Rather, the California test accounts for the state's applicable policies — and thus is consistent with an RVT.

5. Secondary Cost-Effectiveness Tests

This chapter provides information about the potential role of secondary tests, their benefits and limits, and selecting and constructing such tests.

5.1 Summary of Key Points

- The purpose of the primary RVT is to address the threshold question of whether a resource has benefits that exceed its costs and therefore merits acquisition.
- Secondary tests can help address other important questions such as how much utility customers should be expected to pay for a resource that is cost-effective under the RVT, which programs to prioritize if it is not possible to pursue all cost-effective efficiency and/or if there should be constraints on key program design features (e.g., financial incentive levels).
- Secondary tests can also help clarify sensitivities to and/or inform decisions regarding which categories of impacts to include in the RVT.
- There is a wide range of potential secondary tests to consider. Decisions on which secondary tests to use should be a function of the primary purpose(s) for using them and the policy priorities of the jurisdiction.

5.2 Potential Reasons for Using Multiple Tests

As covered in Chapter 3, the RVT is designed to answer for jurisdictions the most fundamental question in assessing efficiency resources: *what is the universe of resources whose benefits exceed their costs and therefore merit acquisition (in lieu of acquiring other supply or demand-side resources)?* However, there can also be value in assessing cost-effectiveness of efficiency resources from other perspectives represented by other tests. Among the potential purposes of using additional tests are:

- **To inform decisions regarding which categories of impacts to include in the primary RVT**. In many cases, the decision as to whether a jurisdiction's applicable policies would support inclusion of a category of impacts in the RVT will be very clear. However, in some cases it may not be quite so obvious or straight-forward. In those cases, there may be value to assessing efficiency resources through two or more potential variations of the RVT to fully understand the sensitivity of results to and therefore the implications of the inclusion or exclusion of one or more categories of impacts in the primary RVT.
- **To inform decisions regarding how much utility customer money could or should be invested to acquire cost-effective savings**. As noted above, the RVT is designed to answer the threshold cost-effectiveness question of which efficiency resources have benefits that exceed costs and therefore merit acquisition. Depending on the policies of a jurisdiction, it may or may not necessarily answer (or fully answer) questions of how those resources should be acquired or who should pay for their acquisition, including how much the utility system (i.e., utility customers through their utility bills) should be prepared to pay to acquire them. Secondary cost-effectiveness test results can be used to help inform answers to such questions.

- **To inform decisions regarding which efficiency programs to prioritize if not all cost-effective resources will be acquired**. As noted above, the RVT is designed to answer the threshold question of which resources are cost-effective. In a policy environment in which all cost-effective resources must be acquired, the RVT may be all that is needed to inform decisions on which efficiency programs to fund. However, jurisdictions that do not attempt to acquire all cost-effective efficiency—for example because of statutorily-set funding constraints—may need to make choices *between* cost-effective resources to decide which cost-effective efficiency programs to fund. Jurisdictions may choose to prioritize programs based on RVT net benefits (i.e., which programs have the greatest economic net benefits under their primary test). Alternatively, they may decide to also consider the results of other cost-effectiveness tests to inform such decisions.
- **To inform efficiency program design**. Related to the two points above, there can be important efficiency program design implications associated with decisions to limit how much utility customers should pay for efficiency resources. If secondary cost-effectiveness tests are used to inform decisions on utility customer spending limits, they can also be used to inform related program design decisions (e.g., rebate levels for efficiency measures).
- **To inform public debate regarding efficiency resource acquisition.** Decisions on which categories of impacts to include in a jurisdiction's RVT may be controversial. Thus, by looking at cost-effectiveness through different perspectives that may be favored by different stakeholders, analysis with multiple tests can provide information useful to ongoing dialogue regarding the merits of different levels or types of efficiency resource acquisition.

5.3 Secondary Tests to Consider

There is a wide range of options jurisdictions can consider for secondary tests. At one end of the spectrum is the UCT, which includes only benefits and costs to the utility system funding efficiency resource acquisition. At the other end of the spectrum is the SCT, which includes the full universe of impacts resulting from efficiency resource acquisition. There are numerous additional options in between. Decisions on which of these options to use as secondary tests should be driven by the primary purpose(s) of the secondary analyses.

5.3.1 Understanding Implications of Impacts Included in the RVT

One appropriate purpose of using multiple tests would be to understand the implications of including or excluding certain categories of impacts in a jurisdiction's RVT (primary test.) In particular, this would allow for the examination of categories of impacts about which there may have been some uncertainty, or even controversy, regarding their inclusion (or exclusion) in the RVT. For example, if there was some uncertainty regarding whether either participant impacts or public health impacts should be included in the RVT, with the ultimate decision being to include both, it may be useful to supplement RVT cost-effectiveness analysis with three sensitivity analyses: (1) removing participant impacts from the RVT; (2) removing public health impacts from the RVT; and (3) removing both participant and public health impacts from the RVT.

5.3.2 Informing Efficiency Program Selection, Spending, and/or Design Decisions

Another purpose of secondary tests could be to inform decisions regarding how much utility customers should pay for efficiency resources, which would have implications for which programs should be prioritized over others and/or program design (particularly participant rebates or other forms of financial incentives). In such a case, the secondary test or tests should be those that best represent the perspective of regulators or other decision-makers regarding such decisions.

For example, if the jurisdiction decides that utility customers (i.e., the utility system) should not pay more for an efficiency resource than they receive back in benefits (i.e., reduced utility system costs), then the UCT would be the secondary test to use. Consider, for example, the following hypothetical scenario for a jurisdiction using the UCT for this purpose:

- a jurisdiction whose RVT included utility system impacts, other fuel impacts, participant impacts, low-income impacts, and environmental impacts;
- a non-low-income efficiency program which provides rebates for efficiency measures equal to 80 percent of the measure costs and has administration, marketing, and other non-incentive costs equal to 20 percent of the total program budget; and
- as illustrated in Table 16, an RVT benefit-cost ratio of 1.67, but with only 40 percent of the benefits being utility system benefits and the other 60 percent being other fuel, participant, and environmental benefits such that the UCT benefit-cost ratio is 0.80.

In this example, the RVT suggests that the efficiency program is cost-effective so that the efficiency resource merits acquisition. However, because the jurisdiction does not want utility customers to pay more for efficiency resources than the value to the utility system (i.e., it does not want utility customers to be paying for other fuel savings, improved participant comfort, or other non-utility benefits), it may choose not to run the program—or at least not run it as initially designed. Another option would be to reduce the rebate level enough so that the utility program does pass the UCT—in this case to something less than 60 percent of the measure cost.

Table 16. Using Secondary Test to Address Program Selection or Design Questions

Impact Category	RVT			UCT		
	Question: Is resource worth acquiring?			Question: How much is it appropriate for utility customers to pay for it?		
	Benefits	Costs	Net Bens	Benefits	Costs	Net Bens
Utility System	$8	Rebate: $8 Admin: $2 Total: $10	-$2	$8	Rebate: $8 Admin: $2 Total: $10	-$2
Participant	$7	$2	$5			
Low Income	$0	$0	$0			
Other Fuels	$3		$3			
Environmental	$2	$0	$2			
Total	$20	$12	$8	$8	$10	-$2
Ben-Cost Ratio			1.67 to 1			0.80 to 1

Alternatively, the policy framework for a jurisdiction may allow a determination that it is acceptable for utility customers to pay for certain types of non-utility benefits. For example, regulators may decide, based on a jurisdiction's existing policies, that they are willing to allow utility customers to pay for benefits from saving other fuels and benefits to low-income customers, but not non-low income participants' benefits, environmental benefits, public health benefits, etc. In this example, the secondary test of interest would be a test that includes utility system impacts, other fuel impacts, and low-income impacts. Under that secondary test, the program in the hypothetical example described above would pass cost-effectiveness screening because the sum of the utility system benefits, other fuel benefits, and low-income benefits (i.e., $11 in aggregate) would exceed the program cost ($10).

5.3.3 Informing Public Debate

If secondary tests are to be conducted to inform public debate, it may make sense to consider a range of secondary tests. This range could include both ends of the cost-effectiveness perspective continuum—the UCT and the SCT—as well as any others that represent perspectives that are held by important stakeholders within the jurisdiction. This process could be useful for assisting in the development of the ultimate primary RVT for a jurisdiction.

PART II.
Developing Inputs for Cost-Effectiveness Tests

6. Energy Efficiency Costs and Benefits

This chapter describes the range of EE costs and benefits (i.e., impacts), both utility system and non-utility system impacts, and information for selecting cost and benefits to include in cost-effectiveness assessments.

6.1 Summary of Efficiency Resource Impacts

In Part I of this NSPM, Chapter 3 set forth the key Framework Steps 2–3 to consider both utility-system and non-utility system impacts. These steps relate to the underlying principles that (a) a jurisdiction’s energy and other relevant policies are central to the decision of which impacts to apply, (b) utility system impacts are the foundation of any cost-effectiveness test, and (c) every cost should be matched with its associated benefit, and vice versa, to ensure symmetry.

This chapter builds on Chapter 3 by providing more detail on the wide range of EE costs and benefits that could be considered in cost-effectiveness testing. Information on the range of impacts includes a description of the cost, benefit, and/or net impact, along with any necessary context or key considerations. Where helpful, additional resources are provided for even further guidance.

Examples of different types of EE resource impacts are summarized in Table 17.

Table 17. Summary of Efficiency Resource Impacts

	Type of Impact	Description
Utility System	Costs incurred or saved by the utility that funds the efficiency resource	Includes costs to utility of acquiring efficiency resources. Savings can include reductions in costs to the utility system associated with both avoided capital investments (e.g., for new generating facilities, environmental compliance and T&D) and avoided variable operating costs (e.g., energy/fuel costs).
Non-Utility System	Participant measure costs	Participant measure costs accrue when the financial incentives provided by efficiency programs cover only a portion of the cost of an efficiency measure. Program participants bear the balance of the measure cost.
	Participant non-resource impacts	Impacts on program participants that are not related to resource (fuel or water) savings. Including asset value, productivity, economic well-being, comfort, health and safety, and customer satisfaction.
	Incremental low-income participant impacts	Impacts on low-income program participants that are different from or incremental to non-low-income participant impacts. Includes reduced foreclosures, reduced transiency, and poverty alleviation.
	Other fuel impacts	Impacts on end-use fuels that are not provided by the funding utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, and wood.
	Water impacts	Impacts on participant water consumption and related wastewater treatment.
	Environment	Impacts associated with CO_2 emissions, criteria pollutant emissions, land use, etc. Includes only those impacts that are not included in the utility cost of compliance with environmental regulations.
	Public health	Impacts on public health. Includes health impacts that do not overlap with participant impacts or environmental impacts, and includes benefits in terms of reduced health care costs.
	Economic development and jobs	Impacts on economic development and jobs.
	Energy security	Reduced reliance on fuel imports from outside the state, region, or country.

This table is presented for illustrative purposes and is not meant to be an exhaustive list. The non-utility impacts presented here can be either a cost or a benefit, or can have a net impact that accounts for both costs and benefits. For a comprehensive discussion of EE resource impacts, see Regulatory Assistance Project 2013c.

The balance of this chapter provides additional detail on the impacts referenced in Table 17. Appendix B provides more information about how the costs and benefits relate to other DERs.

6.2 Utility System Impacts

There are a variety of relevant utility system costs and benefits which should be included in any primary cost-effectiveness test.

6.2.1 Utility System Costs

EE Measure Costs

The utility portion of measure costs can take a variety of forms. Among the most common are rebates provided to program participants, whether end-use customers or other market actors such as retailers, contractors, distributors, and manufacturers. Also common are buy-downs of interest rates for financing investments in efficiency measures.

Other Efficiency Financial Incentives

Other incentives include payments to support trade ally reporting on sales of efficient products, and/or funding or co-funding of marketing of efficient products by trade allies. “Spiffs” are another common incentive. These are sales bonuses provided to retail or contractor sales staff for selling efficient products.

Other Efficiency Program and Administrative Costs

These additional costs support utility outreach to trade allies, technical training, other forms of technical support, marketing, and administration and management of efficiency programs and/or portfolios of programs.

Evaluation, Measurement, and Verification (EM&V)

EM&V costs entail either the analysis of markets for efficiency products and services to inform the design of efficiency programs or the retrospective assessment of the effectiveness of efficiency programs.

Performance Incentives

In regulated utility systems, utilities often receive payments for meeting specific performance metrics related to the success of efficiency programs.

6.2.2 Utility System Benefits

Avoided Energy Costs

These are the values of avoiding the generation or the purchase of electric energy (i.e., kilowatt-hours, or kWh)[27] and/or natural gas resulting from investments in efficiency. The marginal cost of avoided energy can vary considerably by both season and time of day. The load shapes of different efficiency resources—i.e., the portion of energy savings that occur during different seasons and different times of day—can also vary substantially. The value of avoided energy costs should account for such differences to the extent possible and practical.

[27] Typically valued at either forecast wholesale market prices in jurisdictions with competitive wholesale markets or forecast marginal costs of generation for jurisdictions that regulate vertically integrated utilities.

Avoided Generating Capacity Costs

Some portion of the savings of efficiency resources will occur at times that are coincident with system peak demands. Thus, efficiency resources will reduce the amount of money that must be invested in electric generating capacity.[28] The magnitude and type of that reduction will vary considerably from measure to measure, depending on the portion of energy savings that occur during times of system peak demand. Over the long term, efficiency programs can also defer or avoid the need for construction of baseload generation.

Understanding T&D Line Losses

When estimating the magnitude of avoided line losses, it is important to recognize that line losses grow exponentially with load. As a result, the marginal loss rate associated with the last increment of load added to—or removed from—the T&D system (i.e. incremental losses divided by incremental load) is greater than the average loss rate for all load (i.e. total losses divided by total load). Thus, the magnitude of line loss reductions associated with efficiency savings should be based on estimates of marginal—not average—line loss rates (Regulatory Assistance Project 2011).

Further, there should be separate average marginal line loss rates for energy savings and peak savings. By definition, marginal line loss rates at the time of peak will be considerably higher than the weighted average of marginal line loss rates across all hours of the year when energy is saved. Two studies suggest that weighted average marginal loss rates over the course of a year are typically on the order of about 150 percent of average annual loss rates and that marginal loss rates at the hours of system peak (i.e. related to avoided generating capacity) might be twice as great, or on the order of 300 percent of average annual loss rates (Regulatory Assistance Project 2011), (Illinois Commerce Commission 2014).

Avoided Reserves

Electric utilities and/or electric system operators always plan to have at their disposal reserve capacity that can be deployed when a generator shuts down or there is some other form of disruption to the supply of generating capacity. Typically ranging from 7 percent to 25 percent, reserve requirements vary depending on the size of the system and its principle sources of generating capacity (Regulatory Assistance Project 2011). When efficiency resources reduce the amount of generating capacity required for a system, they can also reduce the amount of reserves needed. The value of avoided reserves should either be included in estimates of avoided capacity costs or included separately.

Avoided T&D Costs

Efficiency resources reduce loads on the T&D system. To the extent that at least some portion of those load reductions occur during T&D peaks, they can defer or eliminate the need for investments that would otherwise be required to address localized T&D capacity constraints.

Such deferrals can be passive, meaning they result from system-wide efficiency programs implemented for broad-based economic or other reasons not related to the

[28] There are some exceptions. For example, some heating efficiency measures installed in electric service territories that are summer peaking (and vice versa) will not avoid generating capacity costs. Alternatively, jurisdictions that are forecast to have excess generating capacity well into the future—i.e. beyond the life of the efficiency savings being analyzed—may have no avoidable capacity costs.

intent to defer specific T&D projects. In such cases, the value of avoided T&D costs in some parts of the system are spread across total system T&D peak savings.[29]

They can also be active, such as when geographically targeted efficiency investments are intentionally designed to defer specific T&D projects. The value of active deferrals per peak kW saved will typically be considerably higher than the value per kW for passive deferrals.

In recent years, there has been an increased interest in the value of avoiding distribution costs with DERs. The value of avoided distribution costs can vary significantly depending upon the specific location on the electricity grid. As EE resources become increasingly used, along with other types of DERs, to avoid distribution costs it will be important to develop more sophisticated estimates of the locational values of avoided distribution costs (Analysis Group 2016; ICF International 2016; SEPA 2016; National Grid 2015).

Avoided T&D Line Losses

A portion of all electricity produced at electric generating facilities is lost as it travels from the generating facilities to the homes and businesses that ultimately use the power.[30] Thus, every kWh of efficiency savings realized at the customer's side of the meter equates to more than one kWh of savings at the electric generator. Similarly, every peak kW of savings by end-use customers equates to more than one peak kW of generating capacity. Another key characteristic of line losses is that they expand exponentially as the system experiences higher volumes. For this reason, it is important that calculations account for marginal loss rates for energy savings and peak savings.

Avoided Ancillary Services

Ancillary services are those services required to maintain electric grid stability and security. They include frequency regulation, voltage regulation, spinning reserves, and operating reserves. Efficiency resources may reduce the need for these services by reducing loads on the T&D system. To the extent that these reduced loads lead to lower ancillary services costs, those avoided costs should be included as a benefit.

Energy and/or Capacity Price Suppression Effects

In jurisdictions with competitive wholesale energy and/or capacity markets, prices will be a function primarily of the magnitude of demand. Thus, increased investment in efficiency resources is likely to benefit all consumers through reduced market clearing prices (at least to some extent and for some period of time).

It should be noted that price suppression effects from efficiency resources acquired in a given utility service territory will typically extend beyond the borders of that service territory. This is due to the regional nature of most wholesale markets, which tend to

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29 Estimates of avoided T&D costs can be very utility-specific. For example, 2015 values for New England electric utilities varied between $33/kW-year for Connecticut Light and Power to $200/kW-year for National Grid Rhode Island, with the unweighted average of reported values being $113/kW-year (AESC Study Group 2015). Another benchmarking study found that the avoided distribution cost assumptions across 25 utilities ranged from $0 to $171/kW-year, with an average of just over $48; it also found average avoided transmission cost assumptions to range from $0 to $89/kW-year, with an average of about $20 (Mendota Group 2014).

30 There are analogous "pipe losses" on gas T&D systems, though they tend to be much smaller in magnitude (in percentage terms) than electric losses.

encompass multiple utility service territories. Thus, regulators that include price suppression effects in cost-effectiveness analyses also need to decide whether to include only the value of price reductions to customers in the utility service territory in question, in the entire jurisdiction under the regulator's purview, or in the entire region.

Another consideration is the ongoing debate regarding whether price suppression effects should be considered a benefit or whether there is no net benefit because consumer price decreases are counter-balanced by reductions in generators' profits. This is particularly relevant in jurisdictions that adopt a broader, more "societal" view of impacts on cost-effectiveness analyses.

Avoided Costs of Compliance with RPS Requirements

In jurisdictions that have adopted a Renewable Portfolio Standard (RPS) expressed as a percentage of electric generation, new efficiency resources will by definition reduce the absolute amount of renewable resources that must be purchased. When those required renewable resources are forecast to cost more than other sources of electric generation, their avoided purchase represents avoided RPS compliance costs. Thus the efficiency resources provide an additional utility system benefit, provided the avoided costs are not already reflected in the avoided energy, capacity, and T&D costs discussed above.

Avoided Environmental Compliance Costs

By reducing the amount of electricity that needs to be generated, efficiency resources can lower future costs of complying with environmental regulations. In estimating the value of such savings, it is important to account both for all regulations that have already been promulgated and those that have a significant probability of being promulgated in the future (Regulatory Assistance Project 2012).

Avoided Credit and Collection Costs

All utilities incur some costs associated with customers who are not keeping up with their energy bill payments. Those costs can take a variety of forms, including costs of notices and support provided to customers in arrears, costs associated with shutting off service and turning it back on, carrying costs associated with arrears, and costs of writing off bad debt.

Because efficiency programs lower customers' energy use and energy bills, they can reduce the probability of customers falling behind or defaulting on bill payment obligations. That can be a particularly important benefit of efficiency programs targeted to low-income customers. Since these benefits are costs avoided by the utility and they accrue directly to all utility customers, they are classified here as a utility system benefit.

Reduced Risk

Efficiency resources can reduce utility system risk in several ways. Key among them are: creating a more diverse portfolio of resources that can meet customers' energy needs (all other things being equal, diversity reduces risk); reducing uncertainty in forecasts of future loads and related capital investment needs; and reducing exposure to potential future fuel price volatility associated with other resource types (particularly natural gas, oil, and/or coal-fired generation) (Ceres 2012). Also, as a resource that can be implemented in many relatively small increments, efficiency resources provide more optionality than large central generation facilities.

There are different ways to value risk reduction. For example, the most recent New England regional avoided cost study estimated a "risk premium" of nine percent. This was added to avoided energy costs to account for one aspect of efficiency's risk mitigating effects: uncertainty in the range of future wholesale energy prices (AESC Study Group 2015). Similarly, another screening tool approach is to report cost-effectiveness for several scenarios; e.g., a "best estimate" of future avoided costs, versus a probability-weighted average of future avoided costs.[31] The difference between the two essentially represents a "risk premium" associated with future price volatility. Alternatively, Vermont's regulators have mandated since 1992 that efficiency resource costs be reduced by 10 percent to reflect efficiency's "comparative risk and flexibility advantages" relative to supply resources (VT PSB 1990).

Increased Reliability

By lowering loads on the grid, efficiency can reduce the probability and/or likely duration of customer service interruptions. The magnitude of the value of this benefit will vary, with less value to systems that are projected to be in a good state of reliability for years into the future and more value to systems that are not. There could be some overlap between this benefit and the benefits of reduced risk, avoided capacity costs and/or avoided T&D costs. Thus, any assessment of the value of increased reliability would need to ensure that there is no "double-counting" of overlap with such other benefits.

6.3 Non-Utility System Impacts

This section describes the different types of non-utility system impacts. Many of these impacts can be experienced in the form of costs or benefits, or both. For example, some efficiency measures might increase or decrease the use of other fuels. For each type of impact included in a cost-effectiveness test, both costs and benefits should be included in order to be consistent with the *Principle of Symmetry*.

6.3.1 Participant Impacts

Efficiency program participants typically incur costs and realize benefits beyond those associated with utility system impacts. A more detailed discussion of these costs and benefits is provided below.

Efficiency Measure Costs

Participant measure costs accrue when the financial incentives provided by efficiency programs cover only a portion of the cost of an efficiency measure. Program participants bear the balance of the measure cost. Participant measure costs should include only the participant's portion of the incremental measure costs, i.e., the extent to which the EE measure cost exceeds the baseline measure cost.

Participant Non-Resource Costs and Benefits

Non-resource participant costs and benefits can be divided into residential and business impacts. Residential efficiency measures can provide a wide variety of other non-resource benefits to customers. Some notable examples include improved comfort such as from sealing and insulating leaky homes, improved building durability such as

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[31] One tool for example is Integral Analytics' DSMore cost-effectiveness screening tool. Other approaches include Value-at-Risk, a common approach used to examine risk in probabilistic scenario analyses.

eliminating creation of “ice dams” through sealing and insulating attics, improved health and safety (E4TheFuture 2016a), and improved aesthetics.

For businesses, non-resource benefits can come in a variety of forms, but are commonly distilled down to improved productivity (ACEEE 2015). Such benefits can apply to many types of commercial and industrial customers, including private business, schools, hospitals, government agencies, and more.

Table 18 provides a summary of the different types of participant non-resource benefits.

Table 18. Participant Non-Resource Benefits[32]

Category	Examples
Asset value	• Equipment functionality/performance improvement • Equipment life extension • Increased building value • Increased ease of selling building
Productivity	• Reduced labor costs • Improved labor productivity • Reduced waste streams • Reduced spoilage/defects • Impact of improved aesthetics, comfort, etc. on product sales
Economic well-being	• Fewer bill-related calls to utility • Fewer utility intrusions & related transactions costs (e.g., shut-offs, reconnects) • Reduced foreclosures • Fewer moves • Sense of greater “control” over economic situation • Other manifestations of improved economic stability
Comfort	• Thermal comfort • Noise reduction • Improved light quality
Health & safety	• Improved “well-being” due to reduced incidence of illness—chronic (e.g., asthma) or episodic (e.g., hypothermia or hyperthermia) • Reduced medical costs (emergency room visits, drug prescriptions) • Fewer sick days (work and school) • Reduced deaths • Reduced insurance costs (e.g., for reduced fire, other risks)
Satisfaction/pride	• Improved sense of self-sufficiency • Contribution to addressing environmental/other societal concerns

In some cases, participating customers might experience non-resource costs. For example, some EE measures might increase labor costs or result in increased noise.

Low-Income Participant Costs and Benefits

Low-income participants can incur the same types of costs as non-low-income participants. However, in recognition of the reality that low-income consumers usually cannot afford to pay even a fraction of the cost of efficiency measures, their portion of

[32] See Synapse 2014 and Skumatz 2014 for more detail.

measure costs are often lower by design than the portion borne by non-low-income customers.

Low-income benefits can come in two forms:

1. Benefits include the same *types* of participant benefits as realized by non-low-income residential participants—O&M savings, other fuel savings, water savings, and non-resource benefits described above—though the *magnitude* of some of these benefits are often greater for low-income customers than for non-low-income customers. This is because the condition of the low-income housing stock is often worse and/or because the economic stress under which low-income customers live can result in greater sacrifice of amenity (e.g., comfort) absent efficiency investments.
2. Some participant non-resource benefits—particularly those related to economic well-being—are unique, or largely unique, to this subset of residential customers. Examples include reduced home foreclosures and reduced need to move residence as a result of unpaid bills.

The value of low-income benefits can be substantial, potentially greater than the value of utility system and other energy benefits (SERA 2014).

Operation and Maintenance (O&M) Costs and Benefits

Efficiency measures have the potential to either increase or reduce O&M costs for participants. For example, when an efficient heat pump is installed to displace much less efficient electric resistance heating, there is a modest ongoing annual cost associated with maintaining or servicing the heat pump (compared to no significant maintenance costs for electric resistance baseboard heat). In other cases, efficient technologies provide O&M benefits. Commonly cited examples include efficient lighting technologies such as compact fluorescent lamps (CFLs) and/or Light Emitting Diode (LED) lamps that last longer than their baseline alternatives. They therefore eliminate both the need to purchase and the time and labor required to install several replacement products in the future.

Literature on Non-Energy Impacts

There is a wealth of literature available on the non-energy impacts of EE resources. The following references may be useful for those seeking further information on this topic: ACEEE 2006, Lawrence Berkeley National Laboratory 2014, International Energy Agency 2014, NMR 2011, Oak Ridge National Laboratory 2014, SERA 2006, SERA 2010, SERA 2014, SERA 2016, Tetratech 2012.

Other Fuels Costs and Benefits

Many efficiency measures reduce consumption of both electricity and non-electric energy sources such as natural gas, fuel oil, propane, and wood. The reduction of these fuels provides a benefit that is outside the utility system. Among the most common examples are: building envelope measures such as insulation and air sealing; HVAC distribution system measures such as duct sealing and insulation; and control measures in buildings that are cooled electrically and heated by gas, oil, or propane. In such cases, there is economic value associated with reductions in fuels not supplied by the funding utility.

Conversely, some electric efficiency measures increase consumption of other fuels. For instance, electric efficiency resources can reduce the “waste heat” from inefficient lighting, refrigeration, or air flow components, thereby increasing the need for other fuels used for building space heating. In such cases, the economic benefit of electricity efficiency can be offset—at least in part—by the economic cost of increased consumption of other fuels. Similarly, the economic benefit of reduced consumption of one fuel resulting from fuel-switching measures can be offset—at least in part—by the cost of increasing consumption of other fuels.

Water and Wastewater Costs and Benefits

A number of EE measures also reduce water use. Indeed, in many cases, energy is saved precisely because less water is needed. Examples include low-flow devices (e.g., showerheads, faucet aerators, spray-rinse valves for commercial dish-washing, clothes washers, and improved agriculture techniques). In such cases, there can be economic value associated with both reduced water consumption and reduced wastewater treatment.

6.3.2 Societal Impacts

Environmental Impacts

Efficiency resources can provide a wide range of environmental benefits. These can include reductions in air emissions associated with fossil fuel combustion; the disposal costs of waste from various energy sources (nuclear, coal ash, etc.); the amount of water needed for cooling electric generating stations, extracting natural gas (e.g., "fracking") and other purposes; the amount of land that must be cleared and/or developed for new generating facilities; and adverse impacts on land, air, and water from fossil fuel mining or extraction. Examples of negative environmental impacts include additional waste streams and/or emissions from the production, use, and disposal of efficient products.

It is important to avoid overlap between impact categories. Some positive impacts may be accounted for in calculations of utility system costs under the utility cost of compliance with environmental regulations. Similarly, only those negative impacts that are incremental to impacts from standard or inefficient products should be included.

Public Health Impacts

Some of the environmental emission and waste reductions discussed in the point above result in a reduction in the frequency and/or severity of health problems of populations impacted by fuel extraction and combustion. Such reductions can have positive implications for the level of societal investment required in medical facility infrastructure, as well as in the health, well-being, and economic productivity of the populace.

There could be some overlap between public health benefits and either participant benefits or environmental benefits. Thus, any quantification of public health benefits should ensure that any such overlap is not double-counted.

Economic Development and Jobs

Investment in efficiency resources will result in additional jobs and economic development in several ways.

- First, there are jobs associated with managing and delivering the efficiency programs.
- Second, there are jobs and economic development effects associated with additional work and revenue that such programs funnel to the supply chains

associated with efficiency measures being installed in homes and businesses. These supply chains include: contractors, builders/developers, equipment vendors, product retailers, distributors, manufacturers, and other elements.

- Third, to the extent that the efficiency resources are less expensive than the energy they save, consumers will have more disposable income. When that additional disposable income is spent in the local community (or beyond), it helps to create jobs and spurs economic development.

Conversely, by reducing or avoiding supply-side resources, efficiency resources will reduce the number of job and related local economic development benefits of supply-side investments. Jurisdictions that include economic development and/or job impacts in their primary cost-effectiveness test should account for both positive and negative impacts.

Net economic development and/or job gains are often expressed in terms of increased gross domestic product (GDP) or gross state product (GSP) and/or job-years. It is not clear how these metrics can be translated into monetary terms suitable for inclusion in efficiency benefit-cost analyses, particularly since the drivers of these benefits (efficiency program spending and reduced utility system costs) are already included in the cost-effectiveness analyses. At a minimum, such benefits can be considered without using monetary values. This point is discussed in Chapter 7.

Societal Low-Income Impacts

In some cases there may be low-income community or societal impacts that go beyond those realized by program participants. Examples include poverty alleviation, improving low-income community strength and resiliency, and reduced home foreclosures (any societal impacts from reduced foreclosures must be incremental to the participant impacts related to foreclosures).

Energy Security Impacts

Some jurisdictions have policies designed to increase energy independence and/or energy security. EE investments that reduce imports of various forms of energy inherently advance such goals. There could be some overlap between (a) the benefit of improved energy independence and security and (b) either local jobs and economic development or risk reductions. Thus, any assessment of the magnitude or value of improved energy independence would need to ensure that there is no double-counting of overlap with such other benefits.

Other Impacts

There may be other impacts not included in the list above. These would need to be assessed to ensure they do not overlap with the impacts already defined.

Several of the non-utility system impacts described above, notably the impacts on environment, public health, and economic development, will likely accrue within a broader territory. They can accrue: within the utility service territory in which an efficiency program is run; outside of that service territory but within the jurisdiction of regulators overseeing the program (e.g., within a state); and outside of the jurisdiction governed by the regulators. Thus, in jurisdictions for which energy policies dictate that such impacts be considered, regulators will need to consider the geographic boundary of the impacts.

7. Methodologies to Account for Relevant Impacts

This chapter provides guidance on options for accounting for relevant cost and benefits, including hard-to-quantify impacts as well as approaches for qualitatively including non-monetary impacts.

7.1 Summary of Key Points

All impacts of EE resources that a jurisdiction has chosen to assess via its cost-effectiveness test should ideally be estimated in monetary terms so that they can be compiled readily and compared directly. However, some EE impacts are difficult to quantify in monetary terms, either due to the nature of the impact or the lack of information available about the impacts.

The third key principle described in Chapter 1 is that cost-effectiveness practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize. Approximating hard-to-monetize or hard-to- quantify impacts is preferable to assuming that substantive costs and benefits do not exist or have no value.

Table 12 from Chapter 3.6 summarizes five different approaches that can be used to account for all impacts of EE resources that a jurisdiction has chosen to include in its cost-effectiveness test. The approaches are listed in order of technical rigor and preference.

Preferably, any impacts included in a cost-effectiveness test would be based on monetary values that are rigorously estimated and transparently documented. The first two subsections below discuss using studies from within or outside of a jurisdiction to develop monetary values. The next three sub-sections discuss approaches for addressing hard-to-monetize impacts.

7.2 Jurisdiction-Specific Studies

Jurisdiction-specific studies that quantify costs and monetize relevant benefits as possible are the most rigorous and reliable way to estimate the benefits of EE programs. These studies should use local information to the greatest extent possible, by utility, by state, by province, or by the relevant Regional Transmission Organization/Independent System Operator. These studies should be derived from, or at least be consistent with, the most recent integrated resource planning studies available, wherever they exist.

Jurisdiction-specific avoided cost studies should be comprehensive, transparent, use best practices, and use all relevant information available at the time.

Jurisdiction-specific avoided cost studies should be comprehensive, transparent, use best practices, and use all relevant information available at the time. These avoided cost studies should be updated periodically, to reflect the most recently available information.

Ideally, these avoided cost studies should be prepared by independent third parties, guided by stakeholders, and ultimately reviewed and approved by regulators. For a good example of this approach, see the New England Avoided Energy Supply Cost studies (AESC Study Group 2015). Another example is the California Public Utility Commission cost-effectiveness calculator that embeds the state's official avoided costs in a model to calculate cost-effectiveness (CPUC 2016).

Many jurisdictions have developed technical reference manuals (TRM) to document the costs and operating characteristics of EE resources. TRMs are critical for jurisdictions to support the cost inputs of a jurisdiction's EE cost-effectiveness tests. TRMs should use information that is as up-to-date as possible, and should account for jurisdiction-specific costs as much as possible (Beitel et al. 2016).

7.3 Studies from Other Jurisdictions

In some cases, for some impacts, a jurisdiction-specific study might not provide all the information needed for a cost-effectiveness test. In these cases, it may be appropriate to use results from other jurisdictions. This could include studies prepared for other utilities, other states, other jurisdictions, other regions. It could also include regional or national studies that do not necessarily focus on any one jurisdiction or region.

However, efficiency planners must take care to ensure that the value of a particular cost or benefit in another jurisdiction is equal to, or sufficiently comparable to, the value in the jurisdiction of interest. If not, it may be necessary to adjust values from other jurisdictions before using them. For example, labor costs in one part of the country might be significantly different from other parts of the country. These differences can be accounted for by adjusting costs accordingly.

7.4 Proxies

For the purpose of EE cost-effectiveness analyses, a proxy is a simple, quantitative value that can be used as a substitute for a value that is not monetized by conventional means. Proxies can be applied to any type of cost or benefit that is hard to monetize and is expected to be of significant magnitude (NEEP 2014).

Proxies should be developed by making informed approximations based upon the best information currently available regarding the relevant impact.

Proxy values are typically based on professional judgment; but they should not be developed or perceived as arbitrary values. Proxies should be developed by making informed approximations based upon the best information currently available regarding the relevant impact. This should include a review of relevant literature on the specific impact, as much quantification of the impact that is both feasible and reasonable, a review of proxy values used by other jurisdictions, and consideration of conditions specific to the relevant jurisdiction.

To date, proxies have most frequently been used to account for efficiency resource benefits such as low-income benefits, participant non-energy benefits, or risk benefits (NEEP 2014). However, proxies can also be used to account for other hard-to-monetize efficiency costs and benefits. Proxies could be used, for example, to account for the degradation of energy savings over time, i.e., to account for a “rebound” effect where customers increase energy consumption as a result of reduced energy costs.

Level of Application

Proxy values can be developed for different levels of application, ranging from a single proxy value that applies to an entire portfolio of efficiency resources to different proxy values for each efficiency impact.

When choosing the level of detail to apply to a proxy, there may be a tradeoff between accuracy and feasibility. Proxies that are more detailed are likely to more accurately represent the magnitude of the specific impact in question. However, proxies that are more detailed are also likely to require more information and greater costs to develop.

One advantage of more detailed proxies is that they are more transferrable across programs, across utilities, and over time. For example, an impact-level proxy such as improved health and safety, applied to residential retrofit efficiency programs, is likely to be generally applicable to other residential retrofit programs and remain relatively constant over time. Conversely, a sector-level proxy to account for all participant non-energy benefits for the residential sector should, in theory, be different for different programs and could change over time as the mix of efficiency measures changes over time.

Type of Proxy

Several different types of proxies can be used to account for EE program impacts.

- Percentage Adder: A percentage adder approximates the value of non-monetized impacts by scaling up impacts that are monetized. This type of proxy is the simplest and easiest to apply.
- Electricity Savings Multiplier ($/MWh): An electricity savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of electricity saved by an efficiency resource.
- Gas Savings Multiplier ($/therm): This is the same as an electricity multiplier, but can be applied to programs that primarily, or exclusively, provide gas efficiency improvements. It offers the same advantages and disadvantages of electricity multipliers.
- Fuel Savings Multiplier ($/MMBtu): A fuel multiplier approximates the value of non-monetized benefits or costs relative to the total quantity of fuel saved by an efficiency resource, regardless of the type of fuel saved (e.g., electricity, gas, oil, propane).
- Customer Adder ($/customer): A customer adder (or subtraction) approximates the value of non-monetized benefits relative to the number of customers served by an efficiency program.
- Measure Multiplier ($/measure): A measure multiplier (positive or negative) approximates the value of non-monetized benefits or costs relative to the number of measures installed by an efficiency program.

As with the choice of level of application for a proxy, the choice of which type can result in a tradeoff between accuracy and feasibility. Proxies that are more focused (e.g., by measure, by customer, or by fuel) are more likely to accurately represent the magnitude of the specific impact in question. However, proxies that are more focused are also likely more difficult and expensive to develop.

7.5 Quantitative and Qualitative Information

Some impacts might be difficult to put into monetary terms or to address through proxies. Other impacts may not even be appropriate to put into monetary terms.[33] In these cases, other types of quantitative and qualitative information can be used to inform the cost-effectiveness decision.

Once all efforts to monetize EE costs or benefits have been considered and exhausted, the following steps can be used to consider additional quantitative and qualitative information.

<u>Step A: Provide as much quantitative evidence as possible</u>

For those impacts that remain non-monetized, it may be possible to put them into quantitative terms. Quantitative values generally provide more concrete information for decision-makers to consider, relative to qualitative values or no values at all. Quantitative values of efficiency impacts should be documented in detail, along with justification for why and how the values are relevant to the cost-effectiveness analysis.

For example, jurisdictions that choose to include job impacts might want to present this impact in terms of the number of job-years, rather than a monetized value for jobs. Regulators and efficiency planners could then compare different energy resources according to how many job-years are created by each one.

<u>Step B: Provide as much qualitative evidence as possible</u>

Those impacts that are not monetized or quantified should be addressed qualitatively. Qualitative information can provide some information for decision-makers to consider, relative to no information at all. For those efficiency impacts that are addressed qualitatively, efficiency planners should develop and present as much qualitative evidence as possible regarding those impacts. This evidence should also include a justification for why the considerations are relevant to the cost-effectiveness analysis.

For example, a jurisdiction might choose to consider incremental market transformation benefits without quantifying or monetizing such benefits. In this case, regulators or efficiency planners would consider the incremental market transformation benefits, without necessarily estimating what those benefits are either in terms of energy savings or dollar savings.

<u>Step C: Present quantitative and qualitative evidence alongside monetary results</u>

The monetary impacts of EE resources should be the core of the cost-effectiveness analysis, and ideally should include the vast majority of the impacts being considered. These monetary results should be presented in a transparent, detailed, easily-reviewable way, as described in Section 3.7.

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[33] For example, it may not be appropriate to directly compare the monetary values of economic development and job impacts to the other monetary values in a cost-effectiveness analysis. This issue is addressed in Section 6.3.2.

Any non-monetized impacts of efficiency resources should be presented along-side the monetary impacts.[34] This allows the regulators and other decision-makers to directly compare the monetized, quantitative, and qualitative factors.

Step D: Decide upon the implications of the quantitative and qualitative evidence

Regulators and other decision-makers should then use the monetary, quantitative, and qualitative evidence to decide whether an efficiency resource is cost-effective. In some cases, the monetary results alone might be sufficient to make this decision, e.g., if the monetary benefits exceed the monetary costs, and all the non-monetary evidence indicates there will be additional benefits. The cost-effectiveness decision might also be easy if the monetary benefits are slightly less than the monetary costs, but the non-monetary benefits are clearly significant enough to make up the difference.

In other cases, the decision might not be so clear. For example, if the monetary benefits do not exceed the costs, but the non-monetary benefits are not necessarily significant enough to make up the difference. In these cases, regulators and other decision-makers should make a cost-effectiveness determination, based on all the evidence presented, and with input from relevant stakeholders.

Step E: Document and justify the decision

Finally, the cost-effectiveness decision should be fully documented and justified. This is necessary to provide transparency regarding the decision for the resource in question, and to provide guidance on how similar decisions will be made in future cost-effectiveness analyses.

Example of Using Qualitative Information

The Oregon PUC has two orders (UM551 and UM 590) that set forth a specific set of qualitative conditions under which violation of strict cost-effectiveness limits could be justified to account for non-monetary impacts.

Measures that are not cost effective could be included in utility programs if the following can be demonstrated:

1. The measure produces significant non-quantifiable non-energy benefits. In this case, the incentive payment should be set at no greater than the cost-effective limit (defined as present value of avoided costs plus 10 percent) less the perceived value of bill savings, e.g. two years of bill savings.
2. Inclusion of the measure will increase market acceptance and is expected to lead to reduced cost of the measure.
3. The measure is included for consistency with other DSM programs in the region.
4. Inclusion of the measure helps to increase participation in a cost-effective program.
5. The package of measures cannot be changed frequently and the measure will be cost effective during the period the program is offered.
6. The measure or package of measures is included in a pilot or research project intended to be offered to a limited number of customers.
7. The measure is required by law or is consistent with Commission policy and/or direction.

The conditions above apply both to measures and programs with the exception of Item D (OR PUC, 2014).

[34] Section 3.7 presents an example template for how the monetized, quantified, and qualitative information could be presented.

7.6 Alternative Thresholds

Alternative thresholds are another approach for addressing hard-to-monetize impacts. Such thresholds allow efficiency resources to be considered cost-effective at pre-determined benefit-cost ratios that are different from one (1.0). Regulators can apply a benefit-cost ratio of greater than one (1.0) to account for efficiency resource costs that have not been monetized, or a benefit-cost ratio of less than one (1.0) to account for non-monetized benefits. Regulators can apply alternative thresholds to account for hard-to-monetize impacts at the program, sector, or portfolio level.

Alternative thresholds are, by design, a simplistic way of recognizing that the hard-to-monetize impacts are significant enough to influence the cost-effectiveness analysis. The primary advantage of this approach is that it does not require the development of specific monetary or proxy values. Instead, it is more of a general reflection of the regulators' willingness to be flexible in accounting for certain impacts.

Note that using alternative benchmarks can essentially have the same effect as applying a proxy value if the proxy is applied at the same level of the cost-effectiveness screening (e.g., measure or portfolio). For example, an alternative portfolio level benefit-cost ratio benchmark of 0.9 is equivalent to a portfolio level benefit multiplier of 11 percent; and an alternative benefit-cost ratio benchmark of 0.8 is equivalent to a benefit multiplier of 25 percent.

Regulators should ensure that alternative thresholds are as transparent as possible and are established prior to the cost-effectiveness analysis. Regulators should articulate which resources the alternative thresholds can be applied to, what the threshold is, and the basis for the threshold chosen.

7.7 Sensitivity Analyses

Sensitivity analyses can be used to test the implications of input assumptions that are hard to monetize or whose monetary values are especially uncertain. The cost-effectiveness test can be applied with high, medium, and low estimates of certain inputs to see how the range of estimates will affect the results.

Sensitivity analyses can be used to test the implications of input assumptions that are hard to monetize or whose monetary values are especially uncertain.

Sensitivity analyses of hard-to-monetize inputs offer two advantages. First, they indicate the extent to which these costs or benefits will affect the cost-effectiveness results. Those costs or benefits with a minor impact on the results, regardless of whether a high or low value is used may not require much additional attention. Conversely, those with a major impact on the results might warrant additional research and analysis to improve the estimates of their magnitudes.

Second, sensitivity analyses indicate the extent to which the accuracy of the input will affect the cost-effectiveness results. If an efficiency resource is clearly cost-effective, or clearly not cost-effective, regardless of whether the high or low input assumption is used, then there may be little need or value in improving the accuracy of that input. Conversely, if the input has a notable impact on the cost-effectiveness results depending upon whether the high or low value is used, then it may be necessary to take some additional steps to improve the accuracy of the input or account for it in other ways.

Sensitivity analyses can be used regardless of whether the estimate is monetized, is a proxy, or is somehow addressed with quantitative or qualitative information. However, for administrative ease jurisdictions may want to limit sensitivity analyses to cost-effectiveness inputs that are relatively uncertain and are likely to have a significant impact on the results.

7.8 Reliability of Data

All future costs and benefits of electricity and gas utility resources need to be estimated, and thus there is uncertainty in analyzing the cost-effectiveness of any type of energy resource—demand or supply. Including hard-to-monetize impacts does not change a cost-effectiveness calculation from an absolute to an estimated range of values. It may appear that accounting for hard-to-monetize impacts will reduce the accuracy and precision of the decision, but in fact the results will be more reliable than simply ignoring the hard-to-monetize impacts altogether.

The line between a rigorously established, monetary value and one that is less rigorously established can be subjective, because some level of professional judgement and estimation is typically involved in the development of all cost-effectiveness inputs. For example, the projected values for avoided costs or the effective useful life of an efficiency measure cannot be directly measured in advance.

All substantive impacts should be included in a jurisdiction's analyses, with documentation of the assumptions and analyses. It should account for them in decision-making, recognizing the limits of the reliability of the overall cost-effectiveness analyses. To not include all substantive impacts increases the risk of making an error of omission (not including efficiency resources that are more cost-effective than other resources), as well as an error of commission, including efficiency resources that are not as cost-effective as other resources.

8. Participant Impacts

This chapter expands upon guidance in Subsection 3.3.2 regarding how to determine whether to include participant impacts in the RVT. It explains the policy objectives that might suggest including participant impacts, as well as key considerations regarding those objectives.

8.1 Summary of Key Points

Efficiency program participants experience several types of costs and benefits. Program participant impacts are summarized in Table 7 (Chapter 3) and discussed in more detail in Chapter 6.3.1Appendix C.

When considering whether to include participant impacts in the RVT, it is important to recognize two overarching points. First, the decision of whether to include participant impacts in the primary cost-effectiveness test is a policy decision. Second, if regulators decide to include participant costs in any cost-effectiveness test, the test must also include participant benefits, and *vice versa*.

Table 8 in Chapter 3 provides a summary of the reasons to include participant impacts in the primary cost-effectiveness test, as well counter-points to these reasons. These points and counter-points are discussed in more detail below.

8.2 Policy and Symmetry

When considering whether to include participant impacts in the cost-effectiveness tests, it is important to recognize two overarching points:

1. The decision of whether to include participant impacts in the primary cost-effectiveness test is a policy decision. Regulators may choose to include participant impacts in the primary cost-effectiveness test if that would achieve the jurisdiction's policy goals.
2. If regulators decide to include participant costs in any cost-effectiveness test, the test must also include participant benefits, and *vice versa*. This is necessary to ensure symmetrical treatment of participant impacts, consistent with *Symmetry Principle* set forth in Chapter 1.

With regard to the first point above, some jurisdictions may not have an explicit policy goal regarding whether to include program participant impacts when assessing EE resources. Legislators and other decision-makers may not have addressed this question when promulgating legislation or regulations related to EE resources. In these cases, regulators and other decision-makers should decide whether to include participant impacts based upon the policy context that does exist in the jurisdiction and with appropriate input from relevant stakeholders.

In making this decision, it is important to consider the rationale and implications of including participant impacts in the primary test. These are discussed in the following sections.

8.3 Account for the Impacts on All Customers Combined

One of the reasons for including participant impacts in the primary cost-effectiveness test is to account for the impacts on all utility customers, both program participants and non-participants, regardless of who experiences the impacts. This allows for a broader accounting of impacts than what is included as utility system costs alone.

It is important to recognize that participant impacts fall outside the scope of utility system impacts.

However, it is important to recognize that participant impacts fall outside the scope of utility system impacts, and that this distinction is important when assessing efficiency resource cost-effectiveness. Some of the participant impacts are energy-related while others are not. For example, a customer might use an efficient lighting rebate to install high-end lighting measures that offer aesthetic benefits as well as efficiency improvements. In this case, the customer incurs non-energy costs (higher costs than the low-end efficiency measure), and enjoys non-energy benefits (in terms of improved aesthetics). The presence of non-energy costs and non-energy benefits is an important consideration when deciding whether to include participant impacts in the primary efficiency screening test.

8.4 Account for the Total Cost of the Resource

Another reason sometimes mentioned for including participant impacts in the primary cost-effectiveness analysis is to account for the total cost of the resource. This reason is predicated on the concern that *not* accounting for the total cost of a resource might result in a decision that appears cost-effective but is not. In other words, if the cost of a resource is divided up between two entities (the utility and the participant), then there is a risk that the total cost of the resource exceeds the total benefit, but neither the utility nor the participant would recognize this because each entity is concerned with only its own costs. This could be considered an uneconomic outcome, because the total (utility plus participant) costs might exceed the total benefits. This point is explained in the example in the text box.

If the goal of the cost-effectiveness analysis is to assess the total cost of a resource, then it is necessary to include the total benefits of the resource as well. And the total benefits must include utility system, participant, and societal benefits. In this example, there may be non-utility system benefits (participant or societal) that are not considered. One example is environmental benefits. Continuing the text box example, assume that the resource in question has environmental benefits that are equal to 2 cents/kWh. This would mean that the total benefit of the utility system plus the environmental benefits would be 12 cents/kWh, which is higher than the total costs of 11 cents/kWh. This would mean that the resource is in fact cost-effective when this additional benefit is accounted for.

This example illustrates why, if regulators are interested in the total costs of a resource to avoid uneconomic outcomes, they must also account for the total benefits of the resource. In theoretical terms, this naturally leads to the conclusion that the only way to avoid this type of uneconomic outcome is to apply an SCT that accounts for all the costs and benefits of the resource. Using a test that includes all the participant impacts, without other impacts, will not answer this key question.

However, this conclusion does not mean that regulators must necessarily use an SCT as the primary test for assessing EE cost-effectiveness. If regulators are interested in the total cost of a resource solely to avoid potentially uneconomic outcomes, an SCT could be used as a preliminary, pre-screening test to ensure that all efficiency resources being considered will not result in the uneconomic outcome described above. Then the RVT could be applied as the primary test for determining whether the *relevant* benefits exceed the *relevant* costs.

Finally, if regulators and others are concerned about utility customers paying “too much” for an efficiency resource because the total costs have not been compared to the total benefits, then regulators can require that utility incentives to the participant for EE resources be capped at a level equal to the utility system avoided costs. Continuing the example above, the customer incentive would be capped at 10 cents/kWh, which means that utility customers would never be required to pay more than what the resource is worth to them. This concept is discussed in Subsection 3.3.1 as well.

An Incomplete Picture of Costs and Benefits

Assume that an electricity utility has an avoided cost (including all utility system benefits) of 10 cents/kWh, with retail rates equal to 14 cents/kWh, and that an efficiency resource has a total (incremental) cost of 11 cents/kWh. This efficiency resource would be considered to be not cost effective if the total cost were accounted for (because 11 cents is greater than 10 cents).

Now assume that the utility offers a customer rebate of 5 cents/kWh to adopt this measure, which requires the customer to pay 6 cents/kWh for the remainder of the cost. If the total cost were split between the utility and the participating customer in this way, then the UCT would indicate the resource is cost-effective (because 5 cents is less than 10 cents/kWh), and the customer would conclude that the resource is cost-effective (because 6 cents is less than 14 cents).

In this example, if the total cost were not considered as part of the cost-effectiveness analysis, then *it appears as though* an uneconomic resource would be deemed to be cost-effective from purely a total costs perspective.

However, this conclusion does not account for all the benefits of the resource, and thus provides an incomplete picture of costs and benefits.

8.5 Protect Program Participants

Another reason to include participant impacts in the primary cost-effectiveness test would be to protect program participants. This reason is based on the presumption that including participant impacts in the test will ensure that participants' benefits will exceed costs.

> **The conventional method of including participant impacts in a cost-effectiveness test does not provide a clear indication of the impact on participants.**

There are several considerations regarding the extent to which including participant impacts in the cost-effectiveness test will protect program participants. First, the conventional method of including participant impacts in a cost-effectiveness test does not provide a clear indication of the impact on participants. The benefits to participating customers will be in the form of reduced bills, which will be driven by the energy savings times the retail prices they pay for energy. However, the benefits that are included in the cost-effectiveness test used to account for participant impacts (the TRC test) are in the form of avoided utility costs, not reduced bills. In short, the difference between retail energy prices and utility avoided costs will typically distort the overall impacts on efficiency program participants.

Second, the Participant Cost test is a much more accurate means of protecting efficiency program participants, because this test uses reduced bills as the primary benefit to participants. Also, the Participant Cost test does not dilute the impacts on participants by combining them with the utility system impacts. The Participant Cost test is discussed in more detail in Appendix A.

Finally, the best way to ensure that program participants are protected is through efficiency program design. Successful and effective efficiency programs should be designed to entice customers to participate. This naturally leads to program designs that ensure that participants' benefits exceed their costs. If a program design results in participants' benefits not exceeding costs, then the program is not likely to be successful and should be redesigned. The Participant Cost test can, and often is, used as a way to ensure that programs are designed in a way that will entice customers by providing them with net benefits.

California's Methodology for Treating Non-Energy Costs and Benefits

The California efficiency program administrators have used the TRC test as their primary efficiency cost-effectiveness test, and they have applied an atypical methodology for addressing the challenges associated with the participant impacts. The California program administrators do not include either the participants' non-energy costs or non-energy benefits. In this way, the California TRC test includes only energy-related impacts—the utility system impacts plus the participants' energy-related impacts.

- The participant costs are determined by first estimating the total participant cost, and then subtracting estimated participant non-energy costs from those.
- The participant benefits are defined as only those related to energy impacts. Therefore, all participant non-energy impacts (comfort, health, safety, aesthetics, productivity, etc.) are excluded from the cost-effectiveness analysis.

8.6 Account for Low-Income Program Participant Benefits

Another reason to include participant impacts in the primary cost-effectiveness test would be to allow for the inclusion of low-income participant benefits. Efficiency programs can provide significant benefits to low-income customers, including reduced energy burden, improved health and safety, improved comfort, and more. If program participant impacts are included, then it follows that low-income participant benefits must be included as well.

There are two important considerations when deciding whether participant benefits should be included in the primary test to ensure that low-income benefits are included. First, if a jurisdiction has a policy goal of providing efficiency programs for the benefit of low-income participants, this does not mean that the primary cost-effectiveness test must account for the participant benefits of all customers to do so.

While it is true that if program participant costs are included in a test, then low-income customer benefits should be included as well, the inverse is not necessarily true. A jurisdiction might have a clear policy goal to account for low-income participant benefits, but not a comparable goal to account for all customer participant impacts. In fact, some states already do this. For example, Connecticut and Michigan use the UCT as the primary cost-effectiveness test, but do not require low-income efficiency programs to pass a cost-effectiveness test because of their participant benefits.

The second, and related, consideration is that well-designed low-income programs typically do not include any participant costs. By their very nature, low-income customers are unable or unlikely to participate in efficiency programs if there is any kind of participant cost, or even any significant participant transaction costs. This makes low-income efficiency programs fundamentally different from other efficiency programs. Some of the reasons that might support the inclusion of participant impacts in the primary cost-effectiveness test, such as considering all costs and protecting participants, are not relevant if there are no participant costs.

8.7 Account for Other Fuel and Water Impacts

Similarly, another reason to include participant impacts in the primary cost-effectiveness test would be to allow for the inclusion of other fuel and water impacts. Some efficiency programs can save a significant amount of other fuels, such as electricity (for a gas utility), gas (for an electric utility), oil, propane, or wood. These other fuel savings can sometimes represent a large portion of the savings from efficiency measures, particularly for certain programs such as home retrofit or new construction programs. They can also allow for a fuel-neutral, whole building approach to EE program delivery. If program participant costs are included in the primary cost-effectiveness test, then it follows that participant benefits must be included as well.

While it is true that if program participant costs are included in the primary cost-effectiveness test, then participant other fuel and water impacts must be included as well, the inverse is not necessarily true. A jurisdiction might have a clear policy goal to account for other fuel and water savings, but not a comparable goal to account for all customer participant impacts. This could happen, for example, if a jurisdiction has policy goals supporting fuel-neutral, whole building approaches to efficiency program delivery, but not a comparable goal to account for all participant impacts. A jurisdiction might also have a policy goal of considering all potential fuel savings in order to assess strategic electrification opportunities, but not a comparable goal to account for all participant impacts. This issue is also addressed in Subsection 3.3.4.

8.8 Quality of the Information

Some participant costs and benefits can be difficult to quantify and monetize, for three reasons.

- Total incremental costs.[35] When designing and implementing efficiency programs, the cost to the utility system, i.e., the financial incentive provided to the participant, is known with great certainty. The amount that the participant pays is known with less certainty, and in some cases, can be very difficult to estimate. This is particularly true for efficiency measures where a wide range of customer options and costs are available.
- Non-energy costs. For some efficiency measures, a portion of the incremental costs are a result of product features that are not related to efficiency savings. These non-energy costs often result in a wide range of total incremental costs for efficiency measures, creating a challenge for efficiency planners who typically require one cost estimate for cost-effectiveness analysis.
- Non-energy benefits. The nature of some of these impacts, such as improved productivity, increased health and safety, and improved aesthetics, makes them uncertain, variable by customer and by program. They require different types of analyses to identify them (SERA 2014).

The fact that there are challenges with estimating participant costs and benefits does not, in and of itself, mean that they should be ignored in cost-effectiveness analyses.[36] It does mean that regulators and other decision-makers should consider these challenges, along with the other factors described above, when deciding whether to include participant impacts in the primary cost-effectiveness test.

[35] The term “incremental cost” is used to refer to the portion of cost associated with the improved efficiency of the measure, which is equal to the difference between the cost of the efficiency measure and a baseline measure.

[36] As described in Chapter 1, one of the key principles of cost-effectiveness analyses is that all relevant impacts should be accounted for, even the hard-to-quantify and hard-to-monetize benefits. In addition, Chapter 7 provides methodologies and techniques for accounting for all relevant costs and benefits, including those that are hard to monetize.

9. Discount Rates

This chapter provides guidance on how to determine a discount rate for the RVT that is consistent with the objective of the cost-effectiveness analysis and the jurisdiction's applicable policy goals. The concepts described in this chapter can also be used to determine discount rates for other cost-effectiveness tests, including tests used for DERs and supply-side resources.

9.1 Summary of Key Points

The discount rate reflects a particular pattern of "time preference," which is the relative importance of short- versus long-term impacts. A higher discount rate gives more weight to short-term impacts, while a lower discount rate gives more weight to long-term impacts.

The choice of discount rate is a policy decision that should be informed by the jurisdiction's energy and other applicable policies—and thus should reflect the regulatory perspective, as described earlier in the manual. This perspective recognizes that the objective of efficiency cost-effectiveness analysis is to identify those utility resources that will best serve customers over the long term, while also achieving applicable policy goals of the jurisdiction.

The following steps can assist jurisdictions in determining the discount rate for the RVT:

> <u>Step A: Articulate the jurisdiction's applicable policy goals</u>. These should be the same goals used in developing the RFT and should serve as the basis of the jurisdiction's regulatory perspective.
>
> <u>Step B: Consider the relevance of a utility's weighted average cost of capital (WACC).</u> Is the utility investor time preference consistent with the jurisdiction's applicable policy goals?
>
> <u>Step C: Consider the relevance of the average customer discount rate.</u> Should the discount rate be based on the average utility customer time preference? Does this time preference adequately address applicable policy goals and future utility customers?
>
> <u>Step D: Consider the relevance of a societal discount rate.</u> Is a societal time preference and use of a societal discount rate consistent with the jurisdiction's policy goals and associated regulatory perspective?
>
> <u>Step E: Consider an alternative discount rate</u>. Given that the regulatory perspective may be different from the utility, customer, and societal perspective, the discount rate does not need to be tied to any one of these three perspectives. For example, regulators/decision-makers could decide to use a discount rate that is lower than the utility WACC and the customer discount rate, but higher than the societal discount rate.
>
> <u>Step F: Consider risk implications</u>. Consider using a low-risk discount rate for EE cost-effectiveness if the net risk benefits of EE resources are not somehow accounted for elsewhere in the cost-effectiveness analysis.

9.2 The Purpose of Discount Rates

Discount rates are an essential aspect for assessing any multi-year project or investment. They allow analysts to compare costs and benefits that occur over different time periods.

Some utility costs, such as power plant siting, licensing, and construction, occur in the short term. Other utility costs such as fuel and O&M stretch into the long-term future. A power plant takes a few years to build, and then generates electricity for decades. Many efficiency resources can be implemented within a year or two, and then save energy for many years thereafter.

The discount rate essentially reflects a particular pattern of "time preference," which is the relative importance of short- versus long-term costs and benefits.

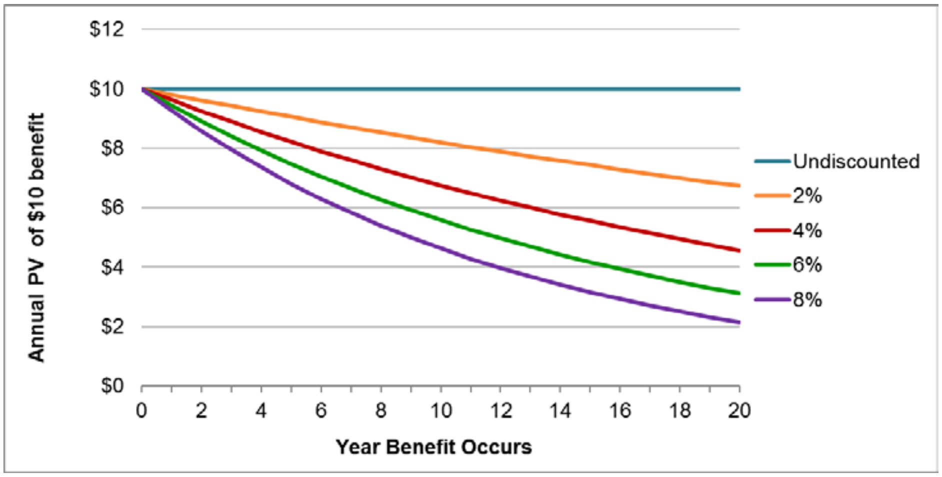
The key point here is that dollars at different times in the future are not directly comparable values; they are apples and oranges. Applying discount rates turns costs and benefits in different years into comparable values.

The discount rate essentially reflects a particular pattern of "time preference," which is the relative importance of short- versus long-term costs and benefits. A higher discount rate gives more weight to short-term costs and benefits than to long-term costs and benefits, while a lower discount rate weighs short-term and long-term impacts more equally. Different economic actors may have differing discount rates, based on their own time preferences.

The choice of discount rates is a critical element of any long-term cost-effectiveness analysis because it has large impacts on the results. This is especially true when the analysis involves long-lived efficiency resources such as building retrofit programs and new construction programs.

Figure 5. Implications of Discount Rates (annual present value dollars) illustrates how EE benefits (e.g., avoided generating fuel costs) can be affected by different discount rates. This example starts with an annual fuel costs savings of $10 per year over the course of a 20-year period. The top, blue line indicates the magnitude of the future avoided costs assuming no discount rate. The other lines present the annual present value of the avoided fuel benefit, depending upon the discount rate used. As indicated, higher discount rates will dramatically reduce the value of avoided fuel savings benefits in Year 20, while lower discount rates have a much smaller impact.

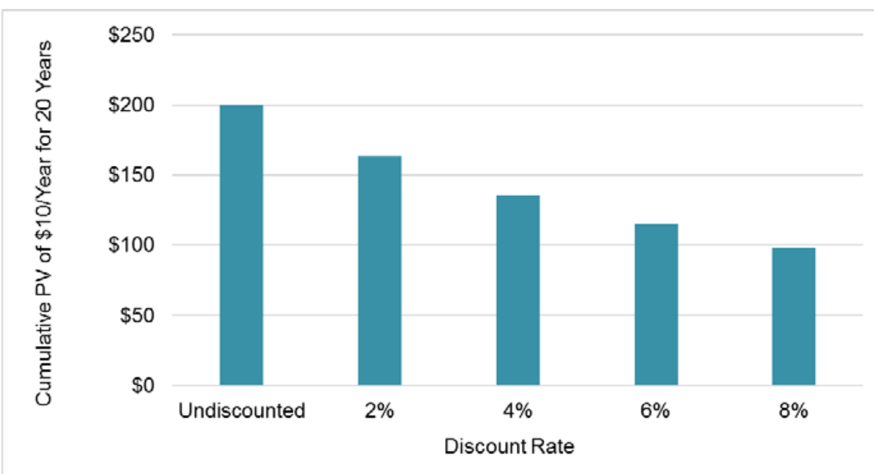
Figure 5. Implications of Discount Rates (annual present value dollars)



These benefits are presented as real dollars (i.e., excluding inflation), and the discount rates are real discount rates.

Figure 6 presents the same information using cumulative present values. Without discounting, a stream of $10 over 20 years would equal $200. The cumulative present value of this stream would be considerably lower. A real discount rate of 8 percent would result in a cumulative present value that is half the cumulative value of the original stream.

Figure 6. Implications of Discount Rates (cumulative present value dollars)



9.3 Commonly Used Discount Rates

Different Perspectives and Time Preferences

Table 19 summarizes several types of discount rates that could be used for energy resource cost-effectiveness assessment. For each type of discount rate, it indicates the time preference represented by that rate, a range of typical values, some brief notes, and sources.

Table 19. Discount Rate Options for Cost-Effectiveness Analyses

Type of Discount Rate	Potential Indicator of Time Preference	Typical Values (in real terms)	Notes and Sources
Societal	Societal cost of capital, adjusted to consider intergenerational equity or other societal values	<0% to 3%	In addition to low-risk financing, government agencies have a responsibility to consider intergenerational equity, which suggests a lower discount rate (US OMB 2003). Society's values regarding environmental impacts might warrant the use of a negative discount rate (Dasgupta, Maler, and Barrett 2000).
Low-Risk	Interest rate on 10-year U.S. Treasury Bonds	-1.0% to 3%	Over the past decade the real interest rate on 10-year U.S. Treasury Bonds ranged between -0.6% and 3.0% percent. As of the publication of this document, the real interest rate on 10-year U.S. Treasury Bonds was 0.4 percent (multpl.com 2017).
Utility Customers on Average	Customers' opportunity cost of money	varies	Customers' opportunity costs can be represented by either the cost of borrowing or the opportunity costs of alternative investments (Pindyck and Rubinfeld 2001, 550). The real rate on long-term government debt may provide a fair approximation of a discount rates for private consumption (US OMB 2003).
Publicly Owned Utility	Publicly owned utility's cost of borrowing	3% to 5%	Publicly owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility Annual Reports.
Investor-Owned Utility	Investor-owned utility's weighted average cost of capital	5% to 8%	Investor-owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility Annual Reports.

Typical values of discount rates are in real terms, as opposed to nominal. Real discount rates should always be applied to real cash flows, and nominal discount rates should always be applied to nominal cash flows. The utility cost of capital should be after-tax.

The typical values presented in Table 19 are provided for illustrative purposes only; other values outside these ranges are also possible. Other points to consider include: that these values can change over time according to changing economic conditions; that there are multiple options for determining a low-risk discount rate; and that different utility customers will have different time preferences, which can be determined in multiple ways. It is also worth noting that the value to use for the societal discount rate is subject to much debate. Further discussion on the range of values for discount rates is beyond the scope of this manual.

EE planners and other stakeholders often recommend that the choice of discount rate for efficiency analysis should reflect the perspective represented by the cost-effectiveness test in use. For example, the U.S. Department of Energy and Environmental Protection Agency's National Action Plan on Energy Efficiency (NAPEE, 2007, 5-4) states that:

- The societal discount rate should be applied when using the SCT.
- The utility weighted average cost of capital should be applied when using the UCT, the TRC test, or the Rate Impact Measure (RIM) test.
- A customer discount rate should be used when applying the Participant Cost test.

While there is some logic to the concept of matching the discount rate to the perspective of the test used, this logic must be applied carefully. First, it is important to recognize the role of the applicable policies in developing the cost-effectiveness test and in determining the appropriate time preference. Second, it is important to be clear on whose perspective is actually represented in particular discount rates. These issues are discussed in the following sections.

The Role of the Cost of Capital

In general, the cost of capital is a key factor in determining discount rates. It indicates the time value of money (or the opportunity cost for alternative investments) for the relevant entity. However, cost of capital is not the only factor that dictates the appropriate discount rate to use for utility investments.

As described above, the primary objective of a utility cost-effectives analysis is to identify those utility resources that will best serve customers over the long term, while also achieving applicable policy goals of the jurisdiction. In light of this objective, the time preference for cost-effectiveness analysis should account for more than just the cost of capital; it should also account for the value of utility service over the long term and applicable policy goals. In other words, important utility services (such as providing safe and reliable power) and important policy goals (such as protecting low-income customers or promoting economic development) are all factors that affect the time preference relevant to the cost-effectiveness analysis.

This point is widely accepted in the application of the societal discount rate. That rate, which is used in multiple applications, reflects more than simply the cost of capital to society. It also reflects societal values and priorities, such as long-term benefits to society, achieving societal goals, addressing the needs and interests of multiple entities across society, and more. In a similar way, the discount rate used for cost-effectiveness analysis could reflect more than just the cost of capital.

9.4 The Regulatory Perspective

The regulatory perspective is an important concept for determining a jurisdiction's primary cost-effectiveness test (as described in Chapters 1 and 2), and associated discount rate. This perspective is typically not recognized or accounted for in the traditional cost-effectiveness tests, yet it is critical for identifying the costs, benefits, and priorities most relevant for any one jurisdiction.

The regulatory perspective is the most relevant perspective for determining a discount rate for the primary cost-effectiveness test.

The regulatory perspective includes the full scope of issues for which regulators and other relevant decision-makers are responsible. It is typically based upon statutes, regulations, executive orders, commission orders, and ongoing policy discussions.

Chapters 1 and 2 address why the regulatory perspective should be used to develop the primary RVT for a jurisdiction, and Chapter 3 provides more detailed guidance. By the same logic, the regulatory perspective is the most relevant perspective for determining a discount rate for the primary cost-effectiveness test.

9.5 The Investor-Owned Utility Perspective

When deciding which discount rate is most appropriate to use for cost-effectiveness analyses, regulators and other decision-makers should carefully consider the relevance of the "utility perspective." The investor-owned utility perspective is discussed in this section, and the publicly owned utility perspective is discussed in the next section.

The Investor-Owned Utility Perspective

The utility WACC is typically used to indicate the time preference for investor-owned utilities (i.e., reflects the time preference of the utility investors, which is the after-tax cost of equity and the cost of debt). The key goal of utility investors is to maximize the returns on their investments. Therefore, the time preference of utility investors is not necessarily the same as the time preference of utility customers, or the regulatory time preference.

Regulators/decision-makers should recognize this important distinction when considering whether to use the utility WACC as a discount rate. The primary objective of the cost-effectiveness analysis is to identify those utility resources that will best serve customers with safe, reliable, low-cost energy services over the long term. This objective is fundamentally different from the objective of maximizing utility investors' returns. These different objectives dictate different time preferences.

Another objective of the cost-effectiveness analysis is to meet the jurisdiction's applicable policy goals, which might include, for example, reducing the energy burden for low-income customers, reducing price volatility, reducing reliance upon fossil fuels, and reducing carbon emissions. Again, this objective of meeting applicable policy goals is fundamentally different from the objective of maximizing utility investors' returns; and these different objectives dictate different time preferences. These longer-term, broader objectives suggest that utility cost-effectiveness analyses should place a higher value on future impacts than utility investors would.

The Cost of Capital of Different Utility Resources

The goal of cost-effectiveness analysis is to compare the relative economics of investing in different resource options. The cost of capital used for resource acquisition varies across resource types. Therefore, even from a utility perspective, the discount rate used for such comparisons should reflect the cost of capital across the resource options under consideration.

A subset of resource costs, such as avoided capacity for generation, transmission, and distribution facilities, are financed by utility debt and equity. In contrast, it is often the case that EE resources and some supply-side resource costs have a much lower cost of capital than the WACC. The utility system costs of acquiring efficiency resources are typically recovered promptly through reconciling charges, and therefore involve no debt or equity costs. Similarly, some supply-side resource costs, such as fuel and purchased power costs are recovered promptly through reconciling charges, and therefore have little to no cost of capital.

In sum, when considering all of the resources used in the cost-effectiveness analyses (EE, avoided energy, avoided purchased power, avoided capacity) the actual WACC is considerably lower than the utility WACC, given the amount of resources that are not financed with debt or equity. This suggests that the utility WACC may be too high for the purposes of comparing the cost-effectiveness of different resources in utility resource planning.

Collection of Revenues to Pay for Debt and Equity

It is sometimes argued that the utility WACC should be used as a discount rate because investor-owned utilities need to collect sufficient revenues to pay dividends and interest to their investors. However, this rationale is not valid because the choice of the discount rate has no impact on the ability of the utility to recover its cost of capital.

The recovery of any debt and equity costs associated with resource acquisition should be included in the calculation of each resource's costs and benefits in the cost-effectiveness analysis. For example, the avoided capital cost of a new power plant should be calculated in terms of annual revenue requirements, which should include depreciation plus the recovery of debt, equity, and taxes over the book life of the asset. Given that the recovery of debt and equity costs should be included in all of the relevant costs and benefits of the resources, there is no need to tie the utility cost of capital to the discount rate.

Unregulated Companies Versus Regulated Utilities

It is also important to consider whether the concept of using the investor-owned utility WACC for a discount rate is appropriate for regulated utilities. While this concept is standard practice for unregulated companies, there are several important differences between unregulated businesses and regulated utilities.

The differences between unregulated businesses and regulated utilities are similar to those described above regarding the utility investor perspective. In fact, the utility investor perspective is essentially the same as the perspective of unregulated businesses, where the primary objective is to maximize profits. Regulated utilities have broader and longer-term objectives, which suggests that regulated utilities should place a higher value on future impacts than unregulated businesses do.

This point is particularly important given that using utility WACC for discount rates is so deeply embedded in utility industry practices. Much of the reason for this is likely due to the conventional practices used in other industries. Before continuing the use of conventional practices for unregulated businesses, regulators/decision-makers should carefully consider whether those conventional practices apply to regulated utilities.

9.6 The Publicly Owned Utility Perspective

Publicly owned utilities, such as public power authorities, municipal utilities, and cooperatives, likely have a different time preference than investor-owned utilities. First, the cost of capital for publicly owned utilities is typically based solely on debt, and therefore is much lower than the WACC of investor-owned utilities.

Second, publicly owned utilities are different from investor-owned utilities by design. One of the reasons for creating publicly owned utilities is to shift the focus of the utility management away from utility investors and toward the needs and interests of customers. Therefore, the time preference of publicly owned utilities is likely to be more aligned with the time preference of utility customers as a whole.

Many publicly owned utilities are overseen and managed by public or customer representatives. For example, municipal utilities are typically overseen by municipal selectmen, councilmen, or boards of customer representatives, and cooperative utilities are typically managed directly by boards of customers or customer representatives.

The boards and agencies that manage publicly owned utilities (i.e., the ultimate decision-makers on resource assessment) essentially act as both the "regulators" and the utility management. Consequently, for publicly owned utilities the utility perspective is naturally more aligned with the "regulatory" perspective. This suggests that publicly owned utilities should naturally place a higher value on long-term costs and benefits than investor-owned utility investors would.

9.7 The Utility Customer Perspective

As described above, the primary objective of utility cost-effectiveness analysis is to identify those utility resources that will best serve customers over the long term, while also achieving applicable policy goals of the jurisdiction. Given that a key objective of the analysis is to serve customers, the utility customer time preference is an important consideration in determining the appropriate discount rate for the analysis.

Regulators/decision-makers should consider several issues when assessing customer time preference. The customers' cost of capital is only one factor that will influence the customers' time preference. Customers are interested in several aspects of utility services beyond just the costs. For example, they may also be interested in reliability of services, price volatility, power quality, etc. These additional aspects of utility service mean that customers might place a different time preference on dollars spent on utility services relative to dollars spent on other products or other investments.

In addition, the customer cost of capital varies considerably across customer classes, and also across customers within classes. Any one cost-effectiveness test, however, can use only one discount rate. Therefore, to the extent that

> In some ways, the time preference from a regulatory perspective is aligned with utility customers' time preference. In both cases, time preference should be consistent with the objective of identifying those resources that will best serve customers. The time preference from the regulatory perspective, however, captures two additional considerations. First regulators/other decision-makers have a responsibility to ensure that utility resources will meet applicable policy goals. Second, regulators have a responsibility to consider both current and future customer interests. For both of these reasons, the regulatory perspective should place a higher value on long-term costs and benefits than the utility customer perspective.

the customer cost of capital is used to inform the determination of a discount rate, it should be an average cost of capital that represents the broad range of utility customers.

9.8 Risk Considerations

Accounting for Risk in Determining the Discount Rate

Risk is often cited as an important factor to consider when determining a discount rate, because risk can affect the value that one might place on long-term versus short-term impacts. However, risk can be represented in different ways in a cost-effectiveness analysis, and it is important to be careful that any treatment of risk in the discount rate recognizes how risk is addressed in the rest of the analysis to ensure that there is no double-counting or under-counting of risk.

Risks can vary considerably across different types of utility resources. For example, EE resources tend to create relatively low risk; generators create different amounts of capital cost, siting, and construction risks; fossil-fueled generators create price escalation and volatility risks; and transmission and distribution facilities impose their own kinds of risks (Ceres 2012).

In general, it is preferable to account for such resource-specific risks separately and explicitly for each resource type, rather than embed it in a discount rate. Discount rates are applied to all resources in a cost-effectiveness analysis. Applying a single discount rate to all resources to reflect risks associated with any one of those resources, could conflate the treatment of resource-specific risk with the overall choice of time preference. Instead, resource-specific risk should be accounted for in developing the cost and benefit inputs to the cost-effectiveness analysis.

Addressing Resource-Specific Risk

There are at least three techniques for addressing resource-specific risk. First, resource-specific risk should be accounted for in the financing costs of the resources themselves. The cost of capital used to determine the cost of each resource should reflect the capital and construction risks associated with that resource. For example, a large new nuclear plant could be assumed to have a high, risk-adjusted, cost of capital to reflect the relevant nuclear capital and construction risks. In contrast, the cost of acquiring EE resources are typically recovered promptly through reconciling charges, and therefore no financing costs are included in their costs.

Once the financial risk of each resource has been accounted for in the financing costs, any other resource-specific risk considerations should be explicitly applied to the costs of those resources. For example, for efficiency resources that avoid potential fuel price volatility or escalating carbon emissions costs (i.e., risk benefits that are not captured in the avoided costs themselves) this risk benefit can be accounted for by either reducing the cost of the efficiency resources or increasing the magnitude of avoided costs (VT PSB 1990).

Finally, the analysis used to develop avoided costs should employ risk assessment techniques to account for the risks associated with the portfolio of resources that define avoided costs (Ceres 2012). There are multiple techniques for portfolio risk assessment, including scenario analyses and probabilistic analyses.

Energy Efficiency Risk

There may be situations where the costs or benefits used in the EE cost-effectiveness analysis do not properly reflect resource-specific risks. For example, the full set of risks associated with avoided costs (e.g., risks associated with avoided fuel costs) may not be fully captured in the avoided costs that are input to the cost-effectiveness analysis.

In such situations, regulators/decision-makers may choose to apply a low-risk discount rate to reflect the net risk benefits of EE resources, because those benefits are not otherwise accounted for in the inputs to the analysis. There are multiple options for determining a low-risk discount rate; the interest rate on 10-year U.S. Treasury bonds is frequently used for this purpose. Several states currently use this low-risk indicator for determining the discount rate their EE cost-effectiveness analyses (NEEP 2014, 43).

9.9 Determining the Discount Rate

9.9.1 Discount Rate for the Resource Value Test

Ultimately, the choice of discount rate is a policy decision—a decision regarding how much weight to give to long-term versus short-term costs and benefits. When determining the discount rate for the RVT, this policy decision should be guided by the regulatory perspective, the same perspective that is used to define that test.

The regulatory perspective may differ from one jurisdiction to another. Therefore, each jurisdiction should determine a discount rate for the RVT based on its own policies and goals. Regulators/decision-makers can take the following steps to make this determination.

The regulatory perspective may differ from one jurisdiction to another. Therefore, each jurisdiction should determine a discount rate for the RVT based on its own policies and goals.

<u>Step A: Articulate Policy Goals</u>

Section 3.1 describes how regulators should identify and articulate policy goals as the first step in the Resource Value Framework. Those same policy goals should be articulated and applied when determining the discount rate for the RVT.

<u>Step B: Consider the Utility Investor Perspective</u>

Regulators should consider whether the utility WACC represents the regulatory time preference, based on the considerations outlined above. Is the utility investor time preference consistent with the jurisdiction's regulatory perspective and policy goals? Is the utility investor time preference the appropriate time preference for resource planning? Does the utility WACC accurately reflect the cost of capital of efficiency and the other resources being assessed?

- If the answer to these questions is "yes," then the utility WACC could be used as the discount rate.
- If the answer to these questions is "no," then a discount rate that is lower than the utility WACC could be used. A lower discount rate would be warranted if either (a) the actual cost of capital across all resources is lower than the utility's WACC; or (b) the regulatory perspective places a greater value on long-term impacts than utility investors.

Step C: Consider the Average Customer Discount Rate

Regulators should consider whether the average customer discount rate represents the regulatory time preference, based on the considerations outlined above. Should the discount rate be based on the average utility customer cost of capital? Does this time preference adequately address applicable policy goals and future utility customer?

- If the answer to these questions is “yes,” then the average customer discount rate as the discount rate could be used.
- If the answer to these questions is “no,” then a discount rate that is lower than the average customer discount rate could be used. A lower discount rate would be warranted if the customer discount rate does not adequately account for policy goals and long-term customer impacts.

Step D: Consider the Societal Discount Rate

Regulators should also consider whether a societal discount rate is appropriate for the primary cost-effectiveness test, based on the considerations outlined above. Is a societal time preference consistent with the jurisdiction’s applicable policy goals?

- If the answer to this question is “yes,” then a societal discount rate could be used.
- If the answer to these questions is “no,” then a discount rate that is higher than the societal discount rate could be used. A higher discount rate would be warranted if the jurisdiction’s places less value on long-term impacts than society would.

Step E: Consider an Alternative Discount Rate

Regulators/decision makers should also consider whether to use a discount rate that is not tied to any one of the three perspectives described above. The regulatory perspective may be different from the perspective of utility investors, customers, and society; thus, the regulatory time preference and discount rate could be different as well.

- Does the jurisdiction’s regulatory perspective suggest a greater value on long-term impacts than that of utility investors?
  - If so, then use a discount rate that is lower than the utility WACC. If not, then use a discount rate that is higher than the utility WACC.
- Does the jurisdiction’s regulatory perspective suggest a greater value on long-term impacts than that of customers?
  - If so, then use a discount rate that is lower than that of customers. If not, then use a discount rate that is higher than that of customers.
- Does the jurisdiction’s regulatory perspective suggest a greater value on long-term impacts than that of society?
  - If so, then use a discount rate that is lower than that of society. If not, then use a discount rate that is higher than that of society.

Step F: Consider Risk Implications

Resource-specific risk issues are best accounted for in estimating the costs of each resource, for example in the resource-specific cost of capital, as adjustments to a resources costs or benefits, and/or in the avoided cost portfolio modeling process.

Nonetheless, there may be situations where the EE costs or benefits do not properly reflect resource-specific risks. For example, the full set of risks associated with avoided costs (e.g., risks associated with avoided fuel costs, risks associated with construction costs) are often not captured in the cost-effectiveness inputs. In such situations, regulators and other decision-makers may choose to apply a low-risk discount rate to reflect the net risk benefits of EE resources, because those benefits are not otherwise accounted for in the inputs to the analysis.

9.9.2 Discount Rates for Different Cost-Effectiveness Tests

The discount rate concepts and considerations described in this chapter are not only relevant to the RVT; they are also relevant to other tests.

The Utility Cost Test

For all the reasons discussed above in Section 9.5, regulators and other decision-makers should be circumspect about using the utility WACC as the discount rate for the UCT. The utility WACC represents the perspective of utility investors, which is fundamentally different from the customer or regulatory perspectives.

This distinction between the customer or regulatory perspectives and utility investor perspectives is relevant regardless of which test is used for EE cost-effectiveness. In all cost-effectiveness analyses, the purpose is to identify resources that best serve customers, and the regulators are in the best position to define what is in the long-term interest of customers. Therefore, the discount rate to use for the RVT should be used for the UCT as well.

In all cost-effectiveness analyses, the purpose is to identify resources that best serve customers, and the regulators are in the best position to define what is in the long-term interest of customers.

Note that the UCT does not represent the perspective of the "utility" *per se* (i.e., in terms of the interests of utility investors or utility management). This test includes all the costs and benefits within the scope of the "utility system" that is used to serve customers, as described in Section 3.3 and Section 6.2.

This distinction between the "utility" (i.e., investors) and the "utility system" (i.e., customers) is important when considering whether the utility WACC is relevant for the UCT. The purpose of the UCT is to identify those resources that will best serve customers, including all costs that customers pay to the utility, and all benefits that customers receive from the utility. This is different from the goal of maximizing value for utility investors.

Total Resource Cost Test

The choice of a discount rate for the TRC test should be based on the same considerations as the choice for the UCT. Adding participant impacts in the test does not change the fact that the purpose of the cost-effectiveness analysis is to provide the best services to customers, and not to maximize shareholder value.

The Societal Cost Test

It is widely accepted that the societal discount rate should be used for the SCT. This is consistent with the notion of aligning the discount rate with the relevant perspective of the test. It is also consistent with the concepts and considerations described above regarding a societal preference for achieving policy objectives and placing greater weight on long-term resource impacts.

The Participant Cost Test

It is widely accepted that a customer-based discount rate should be used in the Participant Cost test. Since the objective of this test it to determine the impacts on program participants, and is not to compare efficiency resources with other resources, a customer-based discount rate is appropriate for this test.

9.9.3 Discount Rates for Analyzing Different Resource Types

The overarching purpose of cost-effectiveness analyses *for any type of utility resource* is to identify those resources that will best serve customers over the long term. Therefore, one of the central concepts of this chapter—that the discount rate should be based on the regulatory perspective, which may be different from the utility investor perspective—is applicable to all types of utility resources.

Regulators and other decision-makers should use the steps described in subsection 9.9.1 to determine the discount rate for analyzing the cost-effectiveness of any type of utility resource. This includes all types of DERs (EE, demand response, distributed generation, and storage), as well as all types of supply-side resources (generation, transmission, and distribution).

The rationale for determining the discount rate for the RVT is relevant across all of these resources. Further, using the same discount rate across all utility resource cost-effectiveness analyses will make the results of those analyses comparable. It will also allow for a more direct comparison across all resource types.

10. Assessment Level

The cost-effectiveness of efficiency resources can be assessed at several levels of aggregation. Assessments can focus on individual measures, individual customer-specific projects, individual programs combining multiple measures and/or projects, sectors (e.g. all residential or all business programs), or portfolios of programs (across all sectors). This chapter discusses the advantages and disadvantages of conducting cost-effectiveness analyses at each of those levels. It also discusses the level at which fixed costs should be included in analyses.

10.1 Summary of Key Points

- Cost-effectiveness assessment at all levels—measure, project, program, sector, and portfolio—can provide valuable insight into program design and implementation. Efficiency planners and other stakeholders may want to analyze efficiency resources at several, if not all, of these levels.
- When applying the primary cost-effectiveness test, or otherwise determining which efficiency resources merit funding, regulators and efficiency planners should rely upon program-level, sector-level or portfolio-level cost-effectiveness results.
- When applying the primary cost-effectiveness test, or otherwise determining which efficiency resources merit funding, regulators and efficiency planners should not rely upon measure-level or project-level cost-effectiveness results. Any advantages of measure-level and/or project-level application are typically outweighed by the disadvantages.
- Consistent with the principle that cost-effectiveness analyses should be forward-looking and focused only on marginal impacts (see discussion in Chapter 1), efficiency program costs should be included in cost-effectiveness analyses only at the level at which they become variable. For example, fixed program costs should not be allocated to measures for the purpose of assessing the cost-effectiveness of individual measures and fixed portfolio-level costs should not be allocated to programs for the purpose of assessing the cost-effectiveness of individual programs.

10.2 Assessment Level Options

10.2.1 Measure-Level Assessment

Resource assessment at the measure level means that each individual measure promoted by an efficiency program must be cost-effective on its own. Screening at the measure level is the most restrictive application of the cost-effectiveness tests.

Measure-level application of cost-effectiveness requirements will essentially guarantee that every measure included in an efficiency program will be cost-effectiveness on its own. However, application of cost-effectiveness requirements at that level can have perverse implications. In some cases, it could reduce the overall net economic benefits of efficiency investments. That can occur for any of the following reasons:

- A customer's interest in a non-cost-effective measure may be key to persuading the customer to install a package of measures that are cost-effective in aggregate. In such cases, the flexibility to promote the non-cost-effective measure as part of a package will lead to greater overall net benefits.
- A customer's interest in a non-cost-effective measure may be key to the development of a relationship with the customer that can lead to installation of cost-effective measures in the future. In that sense, promotion of the non-cost-effective measure can be analogous to a marketing investment.
- Installation of a non-cost-effective measure may be necessary in order to technically or safely enable the installation of other cost-effective measures. An example of this would be the installation of non-cost-effective mechanical ventilation in order to make indoor air quality acceptable when tightening up a building.

Another disadvantage of requiring all measures to be cost-effective is that it can be difficult to account for non-energy impacts, hard-to-monetize impacts, or additional considerations at the measure level. Some non-energy impacts, such as improved health and safety, are obtained through a package of multiple measures, and it is impractical to apply such impacts on each measure.

10.2.2 Project-Level Assessment

Resource assessment at the project level means that the combination of measures implemented together in a package for an individual customer must be cost-effective on its own. Project-level assessments are typically conducted only for projects undertaken by larger business customers for which the transaction cost of a site-specific assessment can be justified.

Project-level application of cost-effectiveness requirements will essentially guarantee that every project included in an efficiency program will be cost-effectiveness on its own. However, application of cost-effectiveness requirements at that level can have some (though fewer) of the perverse implications of measure-level cost-effectiveness requirements. Specifically, supporting the implementation of a non-cost-effective package of measures in which a customer is interested can facilitate development of a relationship with customer that can produce a more cost-effective project later. Also, depending on whether and how participant non-energy benefits are included in cost-effectiveness assessments, the full value of non-energy benefits of a project may not be captured in project-level cost-effectiveness assessments.[37]

[37] The focus of this discussion is solely on the use of cost-effectiveness analysis to determine which investments merit acquisition from either utility system or broader perspectives. Efficiency programs targeted to large business customers often present costs and benefits to individual customers from the customer's perspective (i.e. using retail energy prices rather than avoided system costs, as well as considering customer non-energy benefits that may or may not be part of a jurisdiction's cost-effectiveness test). Similarly, some low-income programs base the determination of which measures to install on the savings-to-investment ratio (i.e., benefit-to-cost ratio) derived using the customer's retail rate. The merits of such customer-focused analyses are fundamentally different from those discussed here regarding utility system resource analyses.

10.2.3 Program-Level Assessment

Resource assessment at the program level means that the measures and/or projects within a program must be cost-effective collectively. Some individual measures and/or projects may not be cost-effective on their own, but could still be included in the program if the overall program were cost-effective.

The primary advantage of this approach is that it best represents the costs and benefits of initiatives that combine a set of actions (e.g., marketing, education, technical support, financial support, etc.) into a single package offered to customers. In addition, resource assessment at the program level avoids the problems noted above regarding missing the interrelationships between measures. These include technical connections and the ability to engage customers in ways that can lead to increasing net economic benefits, as well as the ability to properly capture customer non-energy benefits where warranted.

A disadvantage of this approach is that a program might include one or more measures that are not individually cost-effective and are not needed to account for the concerns addressed above. This has the effect of decreasing to some extent the overall cost-effectiveness of the program. However, this concern can be addressed with sound program design. Efficiency program planners and designers should include only those efficiency measures that effectively contribute to achieving the specific goals of the program.

One other potential concern with program-level screening is that it might preclude certain special programs that address important objectives at the sector or portfolio level. For example, pilot programs to test new and unproven program designs might not appear cost-effective, but might provide future sector or portfolio benefits that cannot be identified in the present. For that reason, jurisdictions that apply program-level screening may want to allow these types of programs to be considered in a sector-level assessment.

10.2.4 Sector-Level Assessment

Resource assessment at the sector level means that the programs within a sector (e.g., low-income, residential, commercial and industrial)[38] must be cost-effective collectively. Some programs may not be cost-effective on their own, but could still be implemented if the combined impact of all of the programs targeted to a given sector were cost-effective.

The primary advantage of this approach is that it indicates the costs and benefits of initiatives to provide a package of efficiency services to an entire sector. This may allow for non-cost-effective programs to be provided to a sector for the purpose of providing a complete set of efficiency services to that sector—an objective often driven by concerns

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[38] Some jurisdictions treat low-income programs as their own "sector," because of the special consideration often given to such customers in program design and delivery. Others treat low-income programs as part of the residential sector. Alternatively, though commercial and industrial customers could be considered to be different "sectors," most efficiency programs targeted to business customers are do not differentiate between those two groups of customers, creating what are called business, non-residential, or commercial & industrial (C&I) sector programs. For the purpose of this manual, we call out low-income, residential, and C&I as three sectors of interest for illustrative purposes only. The conceptual discussion in this section applies regardless of whether low income is treated as its own sector or as part of the residential sector and regardless of whether commercial and industrial are treated as their own sectors or combined.

about equitable access to efficiency programs across a large range and number of customers.

The primary disadvantage of this approach is that it could result in the inclusion of efficiency measures or programs that are not individually cost-effective, thereby decreasing the economic value of the suite of programs for that sector.

10.2.5 Portfolio-Level Assessment

Evaluation at the portfolio level means that the programs within a portfolio (i.e., combining all programs together) must be cost-effective collectively. Some programs may not be cost-effective on their own, but could still be pursued if the combined impact of all of the programs was cost-effective.

The primary advantage of this approach is that it indicates the costs and benefits of the entire suite of EE programs.

The primary disadvantage of this approach is that it could result in implementing efficiency measures or programs that are not cost-effective, thereby decreasing the economic value of the overall portfolio.

10.3 Properly Accounting for Fixed and Variable Costs

A variety of costs are incurred in the acquisition of efficiency resources. It is important that those costs be included at the proper analytical level—e.g., measure, program, sector and/or portfolio—when analyzing the economics of efficiency resources. In a nutshell, only costs that are variable at a given analytical level should be included in cost-effectiveness analysis for that level because they are the only costs that can be avoided as a result of the analysis. Costs that are largely fixed at a particular analytical level should not be "allocated" or otherwise included *at that level;* doing so could lead to rejection of investments whose marginal benefits exceed their marginal costs, thereby lowering net economic benefits. That does not mean that costs that are fixed at a given analytical level should be omitted or ignored altogether. Instead, they can and should be included at higher level analyses at which they are variable and therefore are avoidable.

Only costs that are variable at a given analytical level should be included in cost-effectiveness analysis for that level.

For example, when assessing the economics of efficiency measures, one should include only costs that largely increase or decrease in proportion to the number of measures installed. That will obviously include the cost of the measures themselves, and could also include some program costs that are largely variable. Examples would include rebate processing costs, if the program administrator is paying a vendor a price for every rebate processed, and inspection costs if the program is committed to inspecting a certain percentage of all projects.[39] However, other program costs that are either largely

[39] Alternatively, if the program is committed to inspecting enough projects to get a statistically valid sample, such that the number of inspections would not change significantly or at all between a level of 2000 and

fixed or do not change in proportion to program participation levels, such as the costs of marketing[40] or managing and evaluating the program, should not be included in the economic analysis of individual measures. Rather, they should be included only at program-level cost-effectiveness assessment.

Similarly, portfolio costs that are either largely fixed or do not change in proportion to the number of programs or participation levels in those programs should not be allocated to programs for the purpose of analyzing the economics of individual programs. Rather, they should only be included at portfolio-level cost-effectiveness analysis. Such costs can include portfolio-level marketing, management, and evaluation costs.

The tables below illustrate the importance of accounting for largely fixed costs at the proper analytical level. Table 20 shows that for each of five programs analyzed, the benefits exceed the variable costs of the programs. When largely fixed portfolio costs (equal to about 25 percent of the sum of the five program costs) are added to the sum of the variable impacts of the five programs, the portfolio itself is shown to be cost-effective, providing total net benefits of $800,000.

Table 20. Proper Analysis with 25 Percent Fixed Portfolio Costs Included at Portfolio-Level Analysis

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$250	$250	Yes
Program 2	$300	$200	$100	Yes
Program 3	$1000	$400	$600	Yes
Program 4	$500	$300	$200	Yes
Program 5	$1000	$850	$150	Yes
Sum of all programs	$3300	$2000	$1300	Yes
Portfolio-level costs	$0	$500	-$500	
Total portfolio impacts	$3300	$2500	$800	Yes

Table 21 shows that when the fixed portfolio-level costs are improperly allocated as 25 percent “adders” to each of the programs, the fifth program is no longer seen as cost-effective. If that program is then removed from the portfolio, but with portfolio costs remaining unchanged, the portfolio net benefits decline by $150,000 (i.e., the marginal impact of the fifth program on the portfolio) to $650,000.[41] In short, including fixed costs

10,000 participants, then such inspection costs should be treated as largely fixed and captured at the program level rather than at the measure level.

40 Marketing costs can be somewhat variable in the sense that more marketing should lead to more participation. However, that relationship is rarely linear with the number of measures installed. In addition, and perhaps more importantly, program marketing budgets are often treated as largely fixed. That is, while marketing can play an important role in driving program participation, the costs of marketing do not go up and down as the number of participants goes up and down.

41 Removing the fifth program would require a reallocation of the fixed portfolio cost to the remaining four programs (i.e. each of the remaining four programs would now be allocated a larger portion of the fixed portfolio costs). In this example, the four remaining programs would still all be cost-effective even after absorbing this larger allocation. However, under a different set of example programs, it is possible that the resulting larger allocation of fixed costs would render another program cost-ineffective.

at the improper level can reduce the economic benefits of efficiency resource acquisition.

Table 21. Improper Analysis with 25 Percent Fixed Portfolio Costs Allocated to Individual Programs

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$313	$188	yes
Program 2	$300	$250	$50	yes
Program 3	$1000	$500	$500	yes
Program 4	$500	$375	$125	yes
Program 5	$1000	$1063	-$63	no
Sum of all programs	$3300	$2500	$800	yes
Portfolio-level costs	*Included as adder for each program*			
Total portfolio if non-cost-effective programs excluded	$2300	$1650	$650	yes

11. Analysis Period and End Effects

Analysis period refers to the number of years over which the costs and benefits of a resource investment are forecast and compared. This chapter describes the time period over which cost-effectiveness analysis should be conducted, and how to address any potential 'end effects.'

11.1 Summary of Key Points

- The analysis period should be long enough to capture the full stream of costs and benefits associated with the efficiency resources being analyzed.
- Since most efficiency resource costs are incurred immediately while benefits are spread out over time, failing to use an analysis period that covers the full life of the resource creates an "end effects" problem that biases cost-effectiveness assessments against efficiency resources.
- If it is not possible or is impractical to extend the analysis period to the full life of the efficiency resources being analyzed, then a second best alternative is to amortize costs of the efficiency resource over the full life of the benefits and then compute the net present value (NPV) of both costs and benefits for the same number of years. This better aligns the portion of the costs being considered with the portion of the benefits being considered.

11.2 Analysis Period

Analysis period refers to the number of years over which the costs and benefits of a resource investment are estimated and compared when assessing the resource's cost-effectiveness. The analysis period should be long enough to capture the full stream of costs and benefits associated with the resources under analysis.

For example, an assessment of three years of implementation of an efficiency program which includes measures that last 30 years (a common assumption for some building envelope measures such as insulation upgrades) should have at least a 32-year analysis period—i.e., long enough to assign value to benefits (and costs) for each of the 30 years of life of a measure installed in the third of the three program years analyzed.

If any of the programs are projected to have longer-term market effects, the analysis period should be extended to account for the life of the savings from the post-program period increases in measure installations. For example, if a three-year program promoting building envelop efficiency measures is expected to affect market penetrations of such measures for five years after the three-year program period ends (i.e., in Years 4 through 8), then the analysis period should be extended to 37 years. This is long enough to assign value to the benefits and costs for each of the 30 years of life of a measure installed in the eighth (and last) year of the forecast, post-program period market effects.

11.3 End-Effects Problems

If the cost-effectiveness analysis does not fully capture all of the impacts, there may be what is commonly called an "end effects" problem in which the analysis captures the full cost of an efficiency resource, but not all of the benefits. This occurs because costs are usually incurred at the time of installation of an efficiency measure and therefore are entirely within the analysis period, while benefits are typically spread out over the life of the measure, with some of the benefits occurring after the end of the analysis period. The asymmetrical treatment of costs and benefits results in an analytical bias against efficiency.[42]

This is illustrated in Table 22, which compares the results of using (A) a proper analysis period for an efficiency resource with a 20-year life, and (B) a truncated analysis period of 15 years that creates an end-effects problem. In this hypothetical example, an analysis of the full lifetime benefits of the efficiency resource suggests the resource is cost-effective, with a benefit-cost ratio of 1.15. In contrast, when only 15 of the 20 years of benefits are counted because the analysis period is shorter than the resource life, one would reach the inaccurate conclusion that the resource is not cost-effective, with a benefit-cost ratio of 0.96.

Table 22. How Truncated Analysis Period Leads to End-Effects Problems

Resource Cost	**$1,000**
Annual Benefit	**$80**
Resource Life	**20**
Real Discount Rate	**3%**

A. Full Analysis Period (20 Years)—No End-Effects Problem

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**NPV**
Cost	$1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1000
Benefit	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$1226
Net Benefit																					$226
Benefit-Cost Ratio																					1.23

B. Truncated Analysis Period (15 Years)—End-Effects Problem

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**NPV**
Cost	$1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						$1000
Benefit	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80						$984
Net Benefit																					($16)
Benefit-Cost Ratio																					0.98

11.4 Remedies for End-Effects Problems

The preferred remedy to an end-effects problem is to extend the analysis period to cover the full life of the efficiency resource whose installation is influenced by an efficiency program. However, if that is determined to be impractical, then a "second best"

[42] Note that there can also be some O&M costs or cost savings that occur over the life of an efficiency resource. Use of a proper analysis period is important to accurately reflect the economic value of such O&M changes as well.

alternative is to account for only a portion of the costs of the measure (comparable to the portion of the benefits captured). A simple way to accomplish this is to amortize the costs over the life of the efficiency measure and then calculate the NPV of the resulting annualized costs. This is done over the same period that the NPV of the benefits of the measure are computed.

Table 23 illustrates the result of this approach, using the same assumptions as in the example in Table 22. Part A shows that amortizing costs produces the same NPV result as not amortizing costs when analyzing the full 20-year life of the resource. Part B shows that amortizing the cost in this way produces the same benefit-cost *ratio* under a truncated analysis period as under an analysis period long enough to capture impacts over the full life of the resource. However, the net benefits under this approach ($181 in this example) are lower than under an analysis period that captures impacts over the full life of the resource ($226 in this example). Thus, though this approach is clearly preferable to a truncated analysis that captures all of the resource costs and only some of the resource benefits, it is still better to extend the analysis period to cover the full life of the resources being analyzed, when possible.[43]

Table 23. How Amortizing Costs to Align with Resource Life Ameliorates End-Effects Problems

A. Full Analysis Period (20 Years) with Cost Amortized over Resource Life

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**NPV**
Cost	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$1000
Benefit	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$1226
Net Benefit																					$226
Benefit-Cost Ratio																					1.23

B. Truncated Analysis Period (15 Years) with Cost Amortized over Resource Life

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**NPV**
Cost	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65						$802
Benefit	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80						$984
Net Benefit																					$181
Benefit-Cost Ratio																					1.23

[43] The difference in net benefits can be important if they are necessary to cover fixed program costs to make a program cost-effective (or to cover fixed portfolio costs to make a portfolio of programs cost-effective). For example, if the $1,000 cost assumption in Table 22 and Table 23 was only a per unit efficiency measure cost, and if a program could lead to installation of 10,000 measures, the net benefits from the measures alone would be $1.81 million under the “truncated analysis with costs amortized” approach (i.e., $181 in net benefits per measure from Part B of Table 23 multiplied by 10,000). Thus, if fixed program costs were $2.00 million, the program would appear to not be cost-effective under the “truncated analysis with costs amortized approach.” However, it would be cost-effective if the analysis period covered the full life of the efficiency measures for which the net benefits of the measures would be more accurately calculated at $2.26 million (the $226 per measure from Table 22 Part A multiplied by 10,000 measures).

12. Analysis of Early Replacement

Early replacement occurs when a functioning piece of equipment is replaced with a more efficient model before it normally would have been replaced. This chapter provides guidance on how to analyze the costs and benefits of such early replacement efficiency measures.

12.1 Summary of Key Points

- Under cost-effectiveness tests that do not include participant impacts, the early replacement measure cost is simply the cost the utility incurs to promote the installation of the measure.
- Under cost-effectiveness tests that include participant impacts, the initial cost of an early replacement measure is partially offset by the benefit of deferring the replacement cost that would otherwise have been incurred several years later (i.e., by pushing the date on which the next replacement piece of equipment will have to be purchased much farther out into the future).
- The benefits of early replacement measures are partially a function of the efficiency of the equipment that would have been installed later in the baseline scenario. If the future baseline replacement efficiency is the same as that of the early replacement measure, there is simply one stream of benefits for just the duration of the early replacement period. In other instances, the early replacement measure is more efficient than the new equipment that would otherwise have been purchased in several years (the future baseline replacement efficiency). If this is the case, cost-effectiveness analysis should account for two different streams of impacts: one for the duration of the early replacement period and another for remaining useful life of the early replacement measure.

12.2 Overview

This section addresses why cost-effectiveness analysis of early replacement measures and programs requires special attention, as compared to other common measure categories.

Efficiency measures typically fall into one of four categories:

New Construction: in which a building is going to be constructed, and an efficiency program prompts developers, builders, or contractors to install more efficient products or use more efficient construction practices than they otherwise would have.

Time-of-Sale/Natural Replacement: in which a product is going to be sold and purchased, such as when an appliance breaks down and needs to be replaced, and an efficiency program is designed to persuade a vendor to sell and/or a customer to purchase a more efficient product than they otherwise would have.

Retrofit: in which efficiency programs incentivize customers to install new efficiency measures in an existing space, such as an un-insulated attic.

Early Replacement: in which an existing inefficient product is functioning and would not otherwise be replaced until a future year, and an efficiency program prompts a customer to replace it with a more efficient product sooner than he or she otherwise would have.

For the first three of those efficiency measure classifications, the cost impacts are commonly felt only in the first year (i.e., the incremental cost of an efficiency upgrade over a standard measure that would otherwise have been purchased or the full cost of a retrofit measure). The savings are thus simply the difference between the baseline efficiency and the new efficiency that will recur annually for the life of the measure.

Characterization of both the costs and savings of early replacement measures can be more complicated for two reasons:

- Early replacement changes the timing of costs relative to when they could be incurred in the baseline scenario (i.e., absent the early replacement)—at least in cases where a jurisdiction chooses to include participant costs and benefits; and
- That change in timing can lead to the need to account for multiple baseline assumptions (assumptions that change over time) for both costs and savings.

This section provides guidance on how to account for changes in the timing of costs, and accounting for multiple baselines for both costs and savings/benefits.

12.3 Accounting for Changes in the Timing of Costs

Under an early replacement scenario, there is the initial full cost of the replacement product. However, there are also potential cost savings from not having to buy the new product that would otherwise have been purchased several years into the future (depending on which categories of impacts are included in the cost-effectiveness test selected per guidance in Chapter 3).

Consider, for example, the following hypothetical early replacement scenario:

- The customer has a 10-year-old and still functioning heating system with a 70 percent efficiency rating, and the heating system is normally assumed to last 15 years;
- *Absent an efficiency program influence*, the customer is expected to replace its 10-year-old heating system in five years with a new 90 percent efficient model that will cost $5,000;
- *With the efficiency program influence*, the customer decides to scrap its existing inefficient heating system and replace it today with a new 90 percent efficient model that costs $5,000.

In this case, there would be only five years of savings from the early replacement. If the cost-effectiveness test includes participant impacts, the net cost of the efficiency resource is equal to the $5000 initial cost of the early replacement *minus the NPV of the benefit of deferring a new purchase from the beginning of Year 6 to the beginning of Year 16*.[44] It is critically important that the reduction in cost associated with deferring the next new purchase be incorporated into cost-effectiveness analyses. To not account for

[44] Year 6 is when the customer would otherwise have had to buy a new replacement heating system; Year 16 is when the customer will have to replace the new heating system that was just installed.

it would result in markedly overstating the costs of early replacement measures and programs.[45]

Calculating the value of that deferral requires a cost amortization approach identical to that of minimizing the end-effects problems outlined in Chapter 11. This serves to align the mismatched timing of costs under the baseline condition and the early replacement condition, as illustrated in Table 24.

In short, the amortizing or annualizing of the different purchase times under the baseline and early replacement scenarios has the effect of lining up costs so that the only difference is five years of annualized costs under the early replacement scenario. (The annualized cost under the baseline and early replacement scenarios are the same in Years 6 through 20, cancelling each other out.) Importantly, that also aligns the cost analysis with the benefits analysis (i.e., both costs and benefits occur only in Years 1 through 5).

Table 24. Amortization to Address Mismatched Timing of Baseline and Early Replacement Costs

Costs		Savings	
Efficiency Measure Cost	$5000	Installed Measure Efficiency	90%
Standard New Product Cost	$5000	Standard New Product Efficiency	90%
Resource Life	15	Existing Efficiency	70%
Existing Product Remaining Life	5	Savings Annual Value (Years 1-5)	$600
Real Discount Rate	3%	Savings Annual Value (Years 6 and Beyond)	$0

A. Mismatched Timing of Costs Incurred under Baseline and Early Replacement Program Scenarios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Baseline	-	-	-	-	-	$5000	-	-	-	-	-	-	-	-	-	-	-	-	-	$5000
Early Replace	$5000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$5000	-	-	-	$5000

B. Net Costs and Benefits of Early Retirement Calculated through Cost Amortization

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV
Costs																					
Baseline	-	-	-	-	-	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$4313
Early Replace	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$6231
Net	$407	$407	$407	$407	$407	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$1918
Benefits	$600	$600	$600	$600	$600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$2830
Net Benefits	$141	$141	$141	$141	$141	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$912
Benefit-Cost Ratio																					1.48

12.4 Accounting for Multiple Baselines for Both Costs and Savings

Unlike in the more straightforward example above, there can also be differences between the cost and efficiency of the early replacement measure that is installed today

45 Again, this is only an issue if the cost-effectiveness test includes participant impacts. If it does not, the change in timing of costs associated with future equipment purchases is not relevant.

and the standard new product that would have otherwise been installed five years from now. For example, consider the following modifications to the hypothetical scenario outlined above:

- The customer has a 10-year-old and still functioning heating system with a 70 percent efficiency rating;
- This class of products is normally assumed to last 15 years, so absent an efficiency program influence, the customer is expected to replace its 10-year-old heating system in five years;
- The standard new heating system five years from now is expected to be an 85 percent efficient model that costs $4500;
- Within 10 years, the standard new heating system is expected to be a 90 percent efficient model that costs $5000;
- With the efficiency program influence, the customer opts to scrap its existing old inefficient heating system and replace it today with a new 90 percent efficient model that costs $5000. The new model is not only more efficient than the old heating system it is replacing, but also more efficient than the new heating system the customer would have bought five years from now.

In this case, as depicted in the bottom of

Table 25, there would be five years of the same level of savings as assumed in the first hypothetical example depicted in Table 24 (i.e., the difference between the old 70 percent and the new efficient 90 percent efficient model). However, unlike in the Table 24 example, there would continue to be savings in Years 6 through 20, though the magnitude of those savings would be lower than in the first five years (i.e., the difference between a standard new 85 percent efficient model and an efficient new 90 percent efficient model). Thus, in the hypothetical example, the NPV of benefits is more than $1300 greater ($4140 vs. $2830) than in the Table 24 example.

On the cost side of things, there would not only be a difference between no baseline cost and the amortized costs of the 90 percent efficient model for the first five years, but also a slightly higher amortized cost in the subsequent 15 years to reflect the difference in cost between a new 85 percent efficient model and a new 90 percent efficient model. Thus, in this hypothetical example, the NPV of costs is also greater—by over $400 ($2349 vs. $1918)—than in the Table 24 example.

The net effect of these changes in costs and benefits is an increase in net benefits per measure of nearly $900 (i.e., $1791 vs. $912) relative to the net benefits of the Table 24 example. It should be noted that the direction of this change is unique to this set of hypothetical assumptions. For example, if the cost of a new 85 percent efficient model in Year 6 was assumed to be $3500 instead of $4500 (with the 90 percent efficient model still costing $5000), the net benefits would be virtually identical to those of the example in Table 24. If the 85 percent efficient model cost only $2400 (with the 90 percent efficient model still costing $5000), the measure would actually fall below a 1.00 benefit-cost ratio.

Table 25. Amortization to Address Multiple Baselines for Savings and Costs of Early Replacement

Costs		Savings	
Efficiency Measure Cost	$5000	Installed Measure Efficiency	90%
Standard New Product Cost	$4500	Standard New Product Efficiency	85%
Resource Life	15	Existing Efficiency	70%
Existing Product Remaining Life	5	Savings Annual Value (Years 1-5)	$600
Real Discount Rate	3%	Savings Annual Value (Years 6 and Beyond)	$124

A. Mismatched Timing of Costs Incurred under Baseline and Early Replacement Program Scenarios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Baseline	$0	$0	$0	$0	$0	$4500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5000
Early Replace	$5000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5000	$0	$0	$0	$5000

B. Net Costs and Benefits of Early Replacement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**NPV**
Costs																					
Baseline	-	-	-	-	-	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$3882
Early Replace	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$6231
Net Cost	$407	$407	$407	$407	$407	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$2349
Benefits	$600	$600	$600	$600	$600	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$4140
Net Benefits	$193	$193	$193	$193	$193	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$1791
Benefit-Cost Ratio																					1.76

13. Free-Riders and Spillover

This chapter describes how to address free-riders and spillover effects in cost-effectiveness analyses, for those jurisdictions that focus on net savings for those analyses.

13.1 Summary of Key Points

In jurisdictions that focus on net savings for their cost-effectiveness analyses:

- The treatment of free ridership and spillover effects should be a function of the categories of impacts that a jurisdiction chooses to include in the cost-effectiveness test it adopts pursuant to the process outlined in Chapter 3.
- With regard to free riders:
    - Financial incentives paid to free riders are a cost only if the cost-effectiveness test excludes participant impacts; otherwise the value of the financial incentive to the participant offsets the cost of the financial incentive to the utility system. In other words, the net cost of free riders is zero under any test that includes participant impacts.
    - No benefits from free riders should be included in any cost-effectiveness test.
- With regards to spillover:
    - There are no costs associated with spillover in jurisdictions whose cost-effectiveness test includes only utility system impacts. Spillover should increase costs under tests that include participant impacts.
    - Spillover increases benefits in every test.

Table 26 summarizes which categories of impacts are affected by free-rider and spillover effects, as further discussed below.

Table 26. Categories of Impacts Affected by Free-Riders and Spillover

Category	Free-Riders		Spillover	
	Costs	Benefits	Costs	Benefits
Utility System Impacts	Increase	n/a	n/a	Increase
Participant Impacts	Decrease	n/a	Increase	Increase (if applicable)
Other Impacts	n/a	n/a	Increase (if applicable)	Increase (if applicable)
Total/Net Impact	Increase only if test *excludes* participant impacts; otherwise no net effect	No effect under any test	No increase if test includes only utility system impacts; otherwise an increase	Increase under every test

13.2 Applicability and Definitions

This section addresses the economic concepts underpinning how free-ridership and spillover effects should be treated in cost-effectiveness analyses in jurisdictions that choose to focus on net savings. This section does not address the relative merits of focusing on net savings versus focusing on gross savings, as that is beyond the scope of a guidance document focused solely on the construct and application of cost-effectiveness analysis. This section has no relevance to or application for cost-effectiveness analyses in jurisdictions that choose to focus on gross impacts.

Key definitions to consider in applying guidance from this section are as follows:

- **Free-ridership** refers to efficiency program savings that would have occurred in the absence of the program.[46]
- **Spillover** refers to the installation of efficiency measures or adoption of efficiency practices by customers who did not directly participate in an efficiency program, but were nonetheless influenced by the program to make the efficiency improvement.[47]
- **Gross program impacts** are impacts before or without any adjustments for free-ridership and spillover.
- **Net program impacts** include adjustments for free-ridership and spillover.

13.3 Economic Treatment of Free-Rider Impacts

This section describes which free rider impacts should be included in cost-effectiveness analysis in jurisdictions that focus on net savings, given the categories of impacts that such jurisdictions include in their cost-effectiveness tests.

13.3.1 Utility System Impacts

Benefits: No utility system benefits associated with any savings achieved by free-riders should be included in cost-effectiveness analyses of an efficiency program because the program did not cause those benefits.

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[46] There are three forms of free-ridership: (1) total free-riders—or efficiency program participants who would have installed the same efficiency measures at same time even if the program had not been run; (2) partial free-riders—or participants who would have made some, but not all, of the efficiency investments they made in the absence of the program; and (3) deferred free-riders—participants who would have made the same efficiency investments in the absence of the program, but at a later date (NREL 2014—see: http://www.nrel.gov/docs/fy14osti/62678.pdf).

[47] Spillover can take multiple forms, including both (1) participant spillover—or savings that were influenced by a customer's participation in efficiency program but were beyond those tracked by the program; and (2) non-participant spillover—or savings that were produced by customers who were influenced by a program even though they did not directly participate in it. Participant spillover can be further subdivided into savings that occur at the same site as savings from program participation (known as "inside spillover") and savings that occur at other sites (typically) owned or operated by the same customer (known as "outside spillover"). Participant spillover can also be subdivided into savings that are from measures or actions that are same as those that were recorded by the program (known as "like spillover") or from different kinds of efficiency measures (known as "unlike spillover"). (NREL 2014—see: http://www.nrel.gov/docs/fy14osti/62678.pdf)

Costs: Any financial incentives paid to free-riders should be treated as a utility system cost, because they are part of the overall cost to the utility of operating an efficiency program. For example, if a customer that receives a $100 rebate from a utility efficiency program for an efficiency measure that it would have installed absent the program, the utility system has incurred a $100 cost.

13.3.2 Participant Impacts

Benefits: No participant benefits associated with any savings achieved by free-riders should be included in cost-effectiveness analyses of efficiency programs because the participants would have achieved the same benefits absent the program.

Costs: Financial incentives paid to free-rider participants should be treated as a negative cost to participants because such participants would not have received any such financial support absent the program. This reduction in cost to participants cancels out the cost of free-riders to the utility system. Thus, under cost-effectiveness tests that include both utility system and participant impacts, the net cost of free-riders is zero.

Consider the example in subsection 13.3.1 in which a customer that receives a $100 rebate from a utility efficiency program for an efficiency measure that it would have installed absent the program. As discussed in subsection 13.3.1, the $100 is a utility system cost. Thus, if the jurisdiction's cost-effectiveness test included utility system impacts (as all tests must) but did not include participant impacts, there would be a net cost from the free-rider of $100. However, that changes if the jurisdiction's cost-effectiveness test also includes participant impacts because $100 cost to the utility system is offset by a $100 benefit to the free-rider participant. Put another way, under a test that includes both utility system and participant impacts, the $100 rebate is what is often called a transfer payment. It has distributional impacts—by moving money between customers—but no *net* cost to customers as a whole (which is the perspective that matters under cost-effectiveness tests that include participant impacts as well as utility system impacts).

13.3.3 Other Types of Impacts

Benefits: No other types of benefits associated with any savings achieved by free-riders (other fuel savings, water savings, environmental emission reductions, public health cost savings, poverty reduction, job creation, energy security, etc.) should be included in cost-effectiveness analyses of efficiency programs because they would have been realized absent the program as well.

Costs: Any other types of costs associated with efficiency investments by free-riders should not be included in cost-effectiveness analyses of efficiency programs because they would also have been incurred absent the program.

13.3.4 Summary of Economic Treatment of Free-Riders

Table 27 summarizes the proper economic treatment of free-rider costs and benefits for jurisdictions that focus on net (rather than gross) impacts.

Table 27. Summary of Economic Treatment of Free Riders

Category	Free-Riders	
	Costs	Benefits
Utility System Impacts	Increase	n/a
Participant Impacts	Decrease	n/a
Other Impacts	n/a	n/a
Total/Net Impact	Increase only if test *excludes* participant impacts; otherwise no net effect	No effect under any test

13.4 Economic Treatment of Spillover Effects

This section describes what spillover impacts should be included in cost-effectiveness analysis in jurisdictions that focus on net savings, given the categories of impacts that such jurisdictions include in their cost-effectiveness tests.

13.4.1 Utility System Impacts

Benefits: All utility system benefits associated with spillover effects should be included in cost-effective analyses of an efficiency program because they were caused by the program.

Costs: There are no utility system costs directly associated with spillover effects because, by definition, investments made to produce spillover effects are not subsidized by efficiency programs (i.e., if a customer receives a rebate for installing a measure it is a program participant; spillover effects are produced when customers install measures without taking rebates or other program services).

13.4.2 Participant Impacts

Benefits: In jurisdictions that include participant impacts in their cost-effectiveness test, all spillover participant benefits associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs being analyzed.

Costs: All spillover participant costs associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs in question.

13.4.3 Other Types of Impacts

Benefits: In jurisdictions that include other types of impacts in their cost-effectiveness test (other fuel impacts, water impacts, environmental impacts, public health impacts, low-income impacts, job impacts, energy impacts, etc.), all other benefits associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs under analysis.

Costs: All other types of costs associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs under analysis.

13.4.4 Summary of Economic Treatment of Spillover Effects

Table 28 summarizes economic treatment of spillover costs and benefits.

Table 28. Summary of Economic Treatment of Spillover Effects

Category	Spillover	
	Costs	Benefits
Utility System Impacts	n/a	Increase
Participant Impacts	Increase	Increase (if applicable)
Other Impacts	Increase (if applicable)	Increase (if applicable)
Total/Net Impact	No increase if test includes only utility system impacts; otherwise, an increase	Increase under every test

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Appendix A. Traditional Cost-Effectiveness Tests

This appendix provides a description of the tests that are used for assessing EE cost-effectiveness: the Utility Cost, Total Resource Cost, Societal Cost, Participant Cost, and Rate Impact Measure tests. While these tests are described in the California Standard Practice Manual, those descriptions are not clear for all purposes, and many jurisdictions have deviated from the tests described there. The descriptions below are intended to provide the theoretical underpinnings of *what should be included* in these tests, which might be different from *what is included* in these tests in practice.

A.1 Overview

This appendix provides information on the three commonly used traditional screening tests: the UCT (also known as the Program Administrator Cost Test); the TRC test; and the SCT.[48] As discussed in both the introduction to this manual and in Chapter 4, a jurisdiction using the Resource Value Framework could develop a primary cost-effectiveness test that fully aligns with one of these traditional tests—assuming they are appropriately applied according to the principles set forth in Chapter 2 of this NSPM. This appendix describes the key elements of these three traditional tests. Where necessary, users of this manual can cross-reference Chapter 4 with this appendix to help guide considerations of the relationship with the traditional cost-effectiveness tests.

For each of the traditional tests, this appendix provides:

- A description of the test;
- The relevance of the test for cost-effectiveness assessment;
- The costs and benefits covered under each test; and
- limitations of each test.

This appendix also briefly addresses the Participant Cost and Ratepayer Impact Measure tests, as defined by the CaSPM. However, as discussed below, neither the Participant test nor the RIM test are conceptually consistent with the core principles of cost-effectiveness analysis discussed in Chapter 1. Thus, neither is appropriate as a tool for resource investment choices (though they can provide information that is potential useful for other purposes, such as program design).

Table 29 provides a conceptual overview of the traditional cost-effectiveness tests. Table 30 provides a summary of the various costs and benefits that, to be consistent with the analytical perspective each test is intended to represent, should be included in these tests (although they are not always included in practice). Additional information on each test is provided in the sections that follow.

[48] While most jurisdictions have historically used the CaSPM as the foundation for their cost-effectiveness tests, in practice many jurisdictions have deviated from those tests.

Table 29. Conceptual Overview of the CaSPM Cost-Effectiveness Tests

Test	Perspective	Key Question Answered	Summary Approach
Utility Cost	The utility system	Will utility system costs be reduced?	Includes the costs and benefits experienced by the utility system
Total Resource Cost	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the costs and benefits experienced by society as a whole.
Participant Cost	Customers who participate in an efficiency program	Will program participants' costs be reduced?	Includes the costs and benefits experienced by the customers who participate in the program
Rate Impact Measure	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the costs and benefits that will affect utility rates, including utility system costs and benefits plus lost revenues

Table 30. Costs and Benefits of the CaSPM Cost-Effectiveness Tests

	UCT	TRC Test	SCT	Participant Cost Test	RIM Test
EE Costs:					
Efficiency Program Costs	Yes	Yes	Yes	---	Yes
Efficiency Portfolio Costs	Yes	Yes	Yes	---	Yes
Financial Incentive Provided to Participant	Yes	Yes	Yes	---	Yes
Participant Financial Cost of Efficiency	---	Yes	Yes	Yes	---
Participant Non-Financial Cost of Efficiency	---	Yes	Yes	Yes	---
Participant Increased Resource Consumption	---	Yes	Yes	Yes	---
Societal costs (environmental, health, etc.)	---	---	Yes	---	---
Lost Revenues	---	---	---	---	Yes
EE Benefits:					
Avoided Energy Costs	Yes	Yes	Yes	---	Yes
Avoided Generation Capacity Costs	Yes	Yes	Yes	---	Yes
Avoided T&D Capacity Costs	Yes	Yes	Yes	---	Yes
Avoided T&D Losses	Yes	Yes	Yes	---	Yes
Wholesale Market Price Suppression Effects	Yes	Yes	If applicable	---	Yes
Avoided Environmental Compliance Costs	Yes	Yes	Yes	---	Yes
Avoided RPS Compliance Costs	Yes	Yes	Yes	---	Yes
Avoided Credit and Collection Costs	Yes	Yes	Yes	---	Yes
Participant Resource Savings (fuel, water)	---	Yes	Yes	Yes	---
Participant Non-Resource Benefits	---	Yes	Yes	Yes	---
Reduce Low-income Energy Burden	---	---	Yes	---	---
Environmental Benefits	---	---	Yes	---	---
Jobs and Economic Development Benefits	---	---	Yes	---	---
Societal Health Care Benefits	---	---	Yes	---	---
Increased energy security	---	---	Yes	---	---
Customer Bill Savings	---	---	---	Yes	---

Chapter 6 provides descriptions for the costs and benefits listed here.

A.2 Utility Cost Test

Description: The purpose of the UCT is to indicate whether the benefits of an EE resource will exceed its costs from the perspective of only the utility system. The UCT includes all costs and benefits that affect the operation of the utility system and the provision of electric and gas services to customers. For vertically integrated utilities, this test includes all of the costs and benefits that affect utility revenue requirements. For utilities that are not vertically integrated, this test includes all costs and benefits that affect utility revenue requirements, plus additional costs and benefits associated with market-based procurement of electricity and gas services. The UCT is sometimes referred to as the Program Administrator Cost test, to include those cases where ratepayer-funded EE programs are implemented by non-utility administrators. The UCT is a more accurate name because the costs and benefits included in this test are those that affect the utility system, not those that affect the Program Administrator.

Relevance to EE Assessment: The UCT is useful for identifying the impact of EE on utility system costs and average customer bills, and thus is consistent with the principle that EE is a resource. It is also useful for identifying the extent to which utility investments will provide reduced costs to that same overall group of utility customers, and therefore can have value (among other factors) for informing decisions on relative program priorities, program design (e.g., customer incentive levels) and/or limits on program spending. As discussed in Chapter 3, the UCT should serve as the foundation upon which a jurisdiction's efficiency assessment test is built. From this foundation, other relevant impacts should be added to align the test with the jurisdiction's energy-related policy goals.

Costs Included: The UCT should account for all utility system costs that are incurred to implement the EE resource. This includes all costs that the utility must recover from customers, including: financial incentives for efficiency measures, efficiency program costs, and efficiency portfolio costs.

Benefits Included: The UCT should account for all utility system costs that are avoided by the EE resource. For electricity utilities, this includes avoided energy costs, avoided generation capacity costs, avoided reserves, price suppression effects, avoided transmission costs, avoided distribution costs, avoided ancillary services costs, avoided T&D line losses, avoided environmental compliance costs, avoided RPS compliance costs, avoided credit and collection costs, and the value of reductions in risk and/or increases in system reliability. For gas utilities, this includes avoided gas commodity costs, avoided gas distribution costs, avoided gas storage costs, avoided gas distribution losses, avoided environmental compliance costs, the value of risk mitigation and/or increased reliability, and avoided credit and collection costs.

A.3 Total Resource Cost Test

Description: One of the key principles of cost-effectiveness assessment is that utility EE investments should be evaluated as a resource and compared with other demand-side and supply-side resources. The TRC does so from the combined perspective of the utility system and participants. Thus, this test includes all impacts of the UCT, plus all impacts on the program participants.

Relevance to EE Resource Assessment: The TRC test provides more comprehensive information than the UCT by including the impacts on participating customers. As a result, this test includes impacts on other fuels, which allows for a comprehensive assessment of multi-fuel programs and fuel-switching programs. This test also conceptually includes other non-energy impacts on participants. This is particularly important for low-income programs.

Costs Included: This TRC test should account for all utility system and program participant costs incurred to implement the EE resource. This includes all costs described above for the UCT, plus any costs incurred by the program participant, including: financial cost to purchase efficiency measures; increased consumption of other fuels; increased O&M costs; and participant non-financial costs.

Benefits Included: This test should account for the utility system and program participant benefits that are experienced because of the EE resource. This includes all benefits described above for the UCT, plus any resources and benefits experienced by the program participant, including: other fuel savings, water savings, participant O&M savings, and all other participant non-resource benefits. The appropriate application of TRC requires that all such participant benefits are fully included in order to ensure symmetry with the inclusion of participant costs.

A.4 Societal Cost Test

Description: The purpose of the SCT is to indicate whether the benefits of an EE resource will exceed its costs from the perspective of society as a whole. This test provides the most comprehensive picture of the total impacts of an EE resource. This test includes all the impacts of the TRC test, plus the additional impacts on society. Note that the CaSPM refers to the SCT as a "variation" of the TRC test (CPUC 2001). Since then, many jurisdictions and many studies have referred to the SCT as a separate test with different implications.

Relevance to EE Resource Assessment: The SCT is useful for identifying the total universe of economic impacts of investment in EE resources. It is particularly apt for jurisdictions that have particular interest in a range of societal considerations, such as environmental or economic development concerns, in addition to an interest in minimizing utility system and efficiency program participant costs.

Costs Included: This test should account for all costs that are incurred to acquire the EE resource. This includes all costs described above for the TRC test, plus any costs incurred by society, including environmental costs and reduced economic development.

Benefits Included: This test should account for all of the benefits that result from the EE resource. This includes all benefits described above for the TRC test plus any benefits experienced by society, including: low-income community benefits, environmental benefits, economic development benefits, and reduced health care costs.

A.5 Participant Cost Test

Description: The intended purpose of this test is to indicate whether the benefits of an EE program will exceed its costs from the perspective of the EE program participant. This test includes all impacts on the program participants, but no other impacts.

Relevance to EE Resource Assessment: The Participant Cost test is not appropriate for assessing the value of EE as a resource because, unlike the other four tests described here, it values benefits based on avoided electricity and gas *rates* rather than on avoided utility system *costs*. That violates the fundamental principle that cost-effectiveness analysis should be "forward-looking" (see Chapter 1) because electric and gas rates are designed to recover both variable (i.e., avoidable) costs and fixed (unavoidable) costs, some of which were incurred in the past. An example would be the cost of previous capital investments in the T&D system or generating capacity in vertically integrated utilities.[49]

That said, the Participant test can have value for the purpose of informing efficiency program design (e.g., the level of financial incentives to offer prospective participants and/or the need for marketing to better inform participants of non-energy benefits that they may value) by providing insight into energy bill impact on participants.

Note that the US Department of Energy uses a different test to determine whether to include efficiency measures to participants in federally-funded weatherization assistance programs. It uses the savings-to-investment ratio; where the numerator is the present value of net savings in energy, water, non-fuel, or non-water operation and maintenance costs attributable to the proposed energy or water conservation measure, and the denominator is the present value of the cost of the proposed energy or water conservation measure.

A.6 Rate Impact Measure Test

Description: The purpose of this test is to indicate whether an EE resource will increase or decrease electricity or gas rates (i.e., prices). This test includes all of the costs and benefits of the UCT, plus estimates of the utility lost revenues created by EE programs. When regulators take steps to allow utilities to recover the lost revenues of EE programs, through rate cases, revenue decoupling, or other means, then the recovery of these lost revenues will create upward pressure on rates. If this upward pressure on rates exceeds the downward pressure from reduced utility system costs, then rates will increase, and *vice versa*.

Relevance to EE Resource Assessment: The RIM test should not be used for purpose of determining which efficiency resources are cost-effective—i.e., have benefits that exceed their costs—because, like the Participant test, it does not measure changes in net economic costs across a population; rather, it is a measure of distribution equity. Even in that context, the RIM test only considers one of the three factors regulators should consider when exploring distributional equity concerns: rate impacts, bill impacts, and efficiency program participation rates that affect the portion of customers who will experience net increases or decreases in their bills. See Appendix C for a more detailed discussion of how to more holistically conduct and assess the trade-offs associated with rate impacts.

[49] They may be "avoided" in part by participants, but typically only if a larger portion is then recovered by non-participants. Put another way, a portion of participant benefits is often just a shift in costs from one customer group (participants) to another (non-participants) rather than a true cost savings.

Table 31. Summary of the CaSPM Cost-effectiveness Tests

Test	Purpose	Relevance to EE Assessment
Utility Cost	Indicates the extent to which ratepayer-funded efficiency will reduce costs to that same group of ratepayers; provides a foundation for all efficiency assessment tests	To indicate the impact of efficiency on utility system cost and average customer bills; serves as a foundation for all efficiency assessment tests
Total Resource Cost	Provides a more comprehensive view of EE impacts than the UCT, including impacts of other fuels, which is helpful for multi-fuel programs, and impacts on EE program participants (if properly applied with symmetrical treatment of costs and benefits)	Indicates the total cost of efficiency, regardless of who pays for it
Societal Cost	Most comprehensive test, enabling an assessment of cost-effectiveness based on the universe of costs and benefits of efficiency resource investment	Indicates the full impact of efficiency on society
Participant Cost	Useful in program design, to inform appropriate participant incentives	Not relevant for cost-effectiveness screening
Rate Impact Measure	Indicates whether long-term rates will increase or decrease on average	No appropriate for cost-effectiveness assessment; see Appendix C

Appendix B. Costs and Benefits of Other Types of DERs

This NSPM should serve as a foundation for assessing the cost-effectiveness of DERs. There are, however, important ways in which other types of DERs might need to be treated differently from EE resources. These important DER-specific issues are beyond the scope of this NSPM, but should be addressed by each jurisdiction as they develop cost-effectiveness practices for DERs. This appendix presents an introductory overview of how the types and magnitudes of costs and benefits might differ between EE resources and DERs.

While this NSPM focuses on the assessment of utility EE resources, the core concepts can be applied to other types of utility resources as well. The cost-effectiveness principles described in Chapter 1 and the Resource Value Framework described in Chapter 2 can be used to assess the cost-effectiveness of supply-side resources or distributed energy resources—including EE, demand response, distributed generation, distributed storage, electric vehicles, and strategic electrification technologies.

With regard to DERs, the cost-effectiveness principles and the Resource Value Framework can be used as the foundation for assessing their cost-effectiveness. There are, however, important ways in which other types of DERs might need to be treated differently from EE resources. For example,

- Some costs and benefits of EE might not be applicable to other types of DER, and vice versa. Some of the costs and benefits of EE might have different magnitudes relative to other types of DERs, including time-varying differences and locational differences.[50]
- The policy decision of whether and how to include participant impacts might be different for different types of DERs.
- The approach for addressing rate, bill, and participant impacts might be different for different types of DERs.
- Distributed generation resources can inject power into a distribution grid, while EE resources do not.
- In some jurisdictions, the policy goals supporting other types of DERs might be different from those supporting EE.

These important DER-specific issues are beyond the scope of this NSPM, but should be addressed by each jurisdiction as they develop cost-effectiveness practices for DERs.

This appendix presents an introductory overview of how the types and magnitudes of costs and benefits might differ between EE resources and DERs. The tables below provide an overview of the different types of costs and benefits associated with EE, demand response, distributed generation, and distributed storage. Many of the costs and benefits associated with DERs are the same or similar to those associated with EE. In some cases, however, DERs impose different types of costs or benefits.

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[50] Appendix B provides a comparison of the costs and benefits of EE resources relative to those of other types of DERs.

Table 32 provides an overview of the types of costs and benefits that might be relevant to any type of DER. While most of these were described in Chapter 6, the table also includes some impacts that are not relevant to EE.

Table 32. Relevant Costs and Benefits of Distributed Energy Resources

Costs			Benefits	
Utility System	Program costs	Measure costs (utility portion)	Utility System Avoided Costs	Avoided energy costs
		Other financial incentives		Avoided generation capacity costs
		Other program and administrative costs		Avoided reserves or other ancillary services
		Evaluation, measurement, and verification		Avoided T&D system investment
				Avoided T&D line losses
	Utility incentives	Performance incentives		Wholesale market price suppression
				Avoided RPS or EPS compliance costs
	Integration	Interconnection costs		Avoided environmental compliance costs
	Distribution Capital	Distribution system upgrades		Avoided credit and collection costs
				Reduced risk
Non-Utility	Participant Costs	Measure costs (participant portion)	Low Income	Reduced low-income energy burden
			Public	Public health benefits
		Interconnection fees		Energy security
		Annual O&M		Jobs and economic development benefits
		Participant increased resource consumption	Environmental	Environmental benefits
			Participant Benefits	Participant health, comfort, and safety
		Non-financial (transaction) costs		Participant resource savings (fuel, water)

This table is presented for illustrative purposes, and is not meant to be an exhaustive list.

Different types of DERs might also have different magnitudes for the same type of cost or benefit. For example, one of the core purposes of EE and distributed generation is to reduce energy consumption from the grid, thereby avoiding energy costs on the utility system. Demand response and storage, however, typically *shift* the timing of energy consumption and therefore tend to reduce capacity costs more than energy costs.

These differences are presented in the tables below using circle icons. The greater the shading of the circle, the more often the costs or benefits are typically associated with the resource.

Table 33 below shows the costs and benefits to the utility system typically associated with EE, demand response, distributed generation, and distributed storage.

Table 33. Utility System Costs and Benefits of DERs

		Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Costs					
Utility System	Measure costs (utility portion)	●	◑	○	○
	Other financial incentives	●	●	◑	◑
	Other program and administrative costs	●	◑	◑	◑
	Evaluation, measurement, and verification	●	●	●	●
	Performance incentives	◑	◑	◑	◑
	Interconnection costs	○	○	●	●
	Distribution system upgrades	○	○	●	●
Benefits					
Utility System	Avoided energy costs	●	◑	●	◑
	Avoided generation capacity costs	●	●	●	●
	Avoided reserves or other ancillary services	●	●	●	●
	Avoided T&D system investment	●	●	●	●
	Avoided T&D line losses	●	●	●	●
	Wholesale market price suppression	●	●	●	●
	Avoided RPS or EPS compliance costs	●	◑	●	◑
	Avoided environmental compliance costs	●	◑	●	◑
	Avoided credit and collection costs	◑	◑	◑	◑
	Reduced risk	●	●	◑	◑

This table is presented for illustrative purposes and is not meant to be an exhaustive list.

One of the most notable differences between EE and other DERs is the potential for distributed generation and storage to impose additional distribution system capacity costs and integration costs on the utility system. EE simply reduces energy consumption, while distributed generation and storage often feed electricity into the grid. While low levels of distributed generation and storage are unlikely to impose additional costs on the system, beyond a certain level of penetration, utilities may need to invest in distribution system capacity upgrades. They may also incur integration costs to manage the presence of DERs on the system on a day-to-day basis. For example, system investments may be required to support voltage regulation, upgrade transformers, increase available fault duty, and provide anti-islanding protection (NREL 2013). Integration costs may include scheduling, forecasting, and controlling DERs, as well as procurement of additional ancillary services such as reserves, regulation, and fast-ramping resources.[51]

Table 34 provides an indication of the non-utility system costs and benefits associated with different types of DERs. One type of cost that differs from EE is interconnection fees for distributed generation and distributed storage.

[51] The need to procure fast-ramping resources or reserves is due to both the inflexibility of many fossil-fired units and the variability of most renewable generation.

Table 34. Non-Utility System Costs and Benefits of DERs

		Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Costs					
Non-Utility	Measure costs (participant portion)	●	●	●	●
	Interconnection fees	○	○	◕	◕
	Annual O&M	○	○	●	●
	Participant increased resource consumption	◑	◑	◑	◑
	Non-financial (transaction) costs	◔	●	○	○
Benefits					
Non-Utility	Reduced low-income energy burden	◑	◑	◑	◑
	Public health benefits	●	◑	●	◑
	Energy security	●	◑	●	◑
	Jobs and economic development benefits	●	●	●	●
	Environmental benefits	●	◑	●	◑
	Participant health, comfort, and safety	◑	○	○	○
	Participant resource savings (fuel, water)	◑	○	○	○

This table is presented for illustrative purposes and is not meant to be an exhaustive list.

Appendix C. Accounting for Rate and Bill Impacts

The Rate Impact Measure test is not appropriate for cost-effectiveness analyses for several reasons. Nonetheless, the impacts of EE resources on customer rates and bills is sometimes of great interest to regulators and other stakeholders. This appendix describes a better approach for assessing rate and bill impacts of EE resources through long-term independent assessments of rate impacts, bill impacts, and participation rates.

C.1 Multiple Factors Affecting Rate Impacts

Efficiency resources can affect electricity and gas rates in several ways. First, they will create upward pressure on rates as a result of (a) the recovery of efficiency program administration and implementation costs; and (b) the recovery of lost revenues resulting from EE programs.

Second, they will create downward pressure on rates as a result of avoided costs, including:

- reduced generation capacity costs
- reduced T&D costs, including reduced line losses;
- reduced environmental compliance costs;
- reduced utility credit and collection costs;
- reduced wholesale market prices from price suppression effects, in regions with wholesale electricity markets; and
- reduced average fuel costs, in regions without wholesale electricity markets, as a result of reducing the consumption of the marginal fuels.

The net impact of efficiency resources on electricity and gas rates will be a result of all these different factors combined. Some of these impacts (such as recovery of program costs, wholesale market price suppression effects, and reduced average fuel costs) might occur over the short term, while others (such as reduced generation, transmission, and distribution capacity costs) might occur over a longer time period.

Understanding the impact of lost revenues is essential to understanding the impact of efficiency resources on rates. Lost revenues are the main reason why efficiency resources can be highly cost-effective and yet still result in rate increases. An efficiency resource might pass the UCT, where the long-term utility system benefits are significantly greater than the long-term utility system costs, but still result in increased rates if the lost revenues are high enough. This is often the case in practice where many efficiency programs are cost-effective according to the UCT, but not according to the RIM test.[52]

The recovery of lost revenues is one of the factors that distinguish the impacts of supply-side resources from those of EE resources (as well as all DERs). Supply-side resources do not create lost revenues, because they do not reduce customer consumption.

[52] The only difference between the Utility Cost test and the RIM test is that the latter includes lost revenues as one of the costs of EE resources.

Therefore, an EE resource might be much more cost-effective than a supply-side resource, but still result in upward pressure on rates as a result of the lost revenues.

Furthermore, the timing and impact on rates due to the recovery of lost revenues will depend upon the frequency of utility rate cases. In the years in between utility rate cases, the base rates are typically not increased to allow for the recovery of lost revenues. Instead, the lost revenues will result in reduced earnings for the utility, all else being equal. However, in those cases where the utility has some form of a decoupling mechanism, rates will be adjusted between rate cases and utility earnings will not be affected by the lost revenues.

The RIM test was originally intended to indicate the impact on rates from EE resources (CPUC 2001, 13). However, this test does not provide useful information regarding efficiency resource cost-effectiveness, as described below.

C.2 Limitations of the Rate Impact Measure Test

One of the main limitations of the RIM test is that it does not provide useful information about what happens to rates as a result of efficiency resource investments. A RIM benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts.

Another significant problem with the RIM test is that it typically does not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the sole or primary goal of efficiency resource assessment. Maintaining low utility system costs, and therefore low customer bills, often has priority over minimizing rates. For most customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

In addition, a strict application of the RIM test can lead to perverse outcomes. The RIM test can lead to the rejection of significant reductions in utility system costs to avoid what may be insignificant impacts on customers' rates. For example, a particular efficiency program might offer hundreds of millions of dollars in net benefits under the UCT (i.e., net reductions in utility system costs), but be rejected as not cost-effective if it fails the RIM test. It may well be that the actual rate impact is likely to be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid *de minimus* rate impacts is not in the best interests of customers overall.

Another important problem with the RIM test is that it is not consistent with basic economic theory. The lost revenues from EE are not a new cost created by investments in efficiency resources. Price impacts from lost revenues are caused by the need to recover existing costs over fewer sales. These existing costs that would be recovered through rate increases are not caused by the efficiency resources themselves, they are caused by historical investments in supply-side resources that become fixed costs. In economic terms, these existing fixed costs are referred to as "sunk" costs. In economic theory, sunk costs should not be considered when assessing future investments because they are incurred regardless of whether the future investment is undertaken.

Furthermore, the RIM test results can be misleading. For an efficiency program with a RIM benefit-cost ratio of less than one, the net benefits (in terms of PV$) will be negative. A negative net benefit implies that the investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM test are not new incremental costs associated with efficiency resources. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales, not as a result of incurring new costs. However, efficiency planners frequently present their RIM test results as negative net benefits, implying that the efficiency resource will increase costs, when in fact it will not.

Finally, all electricity and gas resources can result in some form of cross-subsidy. Applying the RIM test to EE resources is inconsistent with how other electricity and gas resources are evaluated for cost-effectiveness.

C.3 Rate Impacts and Customer Equity

In general, efficiency resources will result in lower average customer bills, despite any increase in rates.[53] Those customers that participate in an efficiency program will typically experience lower bills, while those that do not participate may experience higher rates and therefore higher bills.[54] Therefore, the rate impacts of EE resources are not a matter of cost-effectiveness. Instead, they are a matter of customer equity; between customers who participate in efficiency programs and those who do not.

Another limitation of the RIM test is that it does not provide the specific information that efficiency planners and regulators need to assess the equity impacts of efficiency resources. In order to understand equity impacts, it is necessary to simultaneously assess (a) the impacts of efficiency resources on long-term average rates; (b) the impacts of efficiency resources on long-term average customer bills; (c) and the extent to which customers participate in efficiency resource programs (over time) and thereby experience lower bills.

Put another way, regulators and other policymakers need to be able to compare the magnitude of bill reductions to the participating customers against the magnitude of any rate and (therefore) bill increases to non-participating customers and the portion of customers expected to experience such adverse effects. The RIM test does not provide this essential information. It only assesses whether rates will go up or not. It does not divulge the magnitude of the increase; nor does it indicate how many customers will experience the impact as an increase in their bills.

Some of the problems of the RIM test stem from the fact that it attempts to combine cost-effectiveness issues and equity issues into a single calculation. It combines the lost revenues (which are historical, unavoidable costs that drive equity issues) with the resource costs and benefits (which are future, avoidable costs that drive cost-effectiveness issues). By combining cost-effectiveness and equity issues into a single

[53] This is not always the case. Many demand response programs can lead to reduced rates, because they involve very little lost revenue recovery. Some EE programs can lead to reduced rates, depending upon program costs, avoided costs, and lost revenue recovery.

[54] It is important to note that all customers experience some of the benefits of efficiency resources—regardless of whether they participate in the programs. In particular, efficiency resources can reduce the need for new generation capacity, reduce wholesale capacity prices, reduce wholesale energy prices, reduce T&D costs, improve system reliability, reduce risk, and more. All of these benefits accrue to all customers. Nonetheless, it is also generally true that efficiency participants will experience greater benefits than non-participants, due to the immediate reduction in their electricity bills.

calculation, the RIM test actually conflates the two issues and provides results that are not meaningful for either one.

The solution to this problem is to undertake two separate analyses. The cost-effectiveness analysis should account for all the future, avoidable costs and benefits, using the principles and concepts described in this manual. A separate rate impact and equity analysis can be used to assess the distributional impacts of the EE resource (US OMB 2003, 14), by analyzing the likely long-term impact on rates, bills, and customer participation.

C.4 A Better Approach for Analyzing Rate Impacts

A thorough understanding of the implications of efficiency rate impacts requires analysis of three important factors: rate impacts, bill impacts, and participation impacts.

- **Rate impacts** provide an indication of the extent to which rates for all customers might increase due to efficiency resources.
- **Bill impacts** provide an indication of the extent to which customer bills might be reduced for those customers that install efficiency resources.
- **Participation impacts** provide an indication of the portion of customers will that will experience bill reductions or bill increases. Participating customers will generally experience bill reductions while non-participants might see rate increases leading to bill increases.

Taken together, these three factors indicate the extent to which customers as a whole will benefit from efficiency resources, and also the extent to which efficiency resources may lead to distributional equity concerns. It is critical to estimate the rate, bill and participant impacts properly, and to present them in terms that are meaningful for considering distributional equity issues (SEE Action 2011a).

Rate Impact Estimates

Rate impact estimates should account for all factors that impact rates. This would include all avoided costs that might exert downward pressure on rates, as well as any factors that might exert upward pressure on rates. Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the jurisdiction's ratemaking practices.

Rate impacts should be estimated over the long term, to capture the full period of time over which the efficiency savings will occur. The study period should include all of the years in which efficiency resources are implemented, plus enough years to include the full measure lives of the last efficiency resources installed. This is necessary to capture the full effect of the downward pressure on rates from avoided generation, transmission, and distribution costs.

Rate impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by efficiency planners and regulators. For example, they should be put in terms of ¢/kWh impacts, dollars per month, percent of total rates, or percent of total bill.

Rate impacts can be markedly different across different customer types. Therefore, it may be necessary to analyze the rate impacts for different customer sectors. Conducting a rate impact analysis for every customer class is probably too burdensome and not necessary. Instead, analyses can be conducted for key customer types such as residential, small commercial, and large commercial and industrial.

Bill Impact Estimates

Bill impact estimates should build upon the estimates of rate impacts. While rate impacts apply to every customer within a rate class, bill impacts will vary between participants and non-participants. Further, bill impacts will vary depending upon the type of efficiency program and the amount of efficiency savings from the program. For these reasons, it may be appropriate to estimate bill impacts by efficiency program, or at least the key efficiency programs.

As with rate impacts, bill impacts should be estimated over the long term, to capture the full period of time over which the efficiency savings will occur. The study period should include all of the years in which efficiency resources are implemented, plus enough years to include the full measure lives of the last efficiency resources installed. This is necessary to capture the full effect of the downward pressure on bills from avoided generation, transmission, distribution, and other costs collectively born by ratepayers.

As with rate impacts, bill impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by efficiency planners and regulators. For example, they should be put in terms of dollars per month or percent of total bill.

Participation Estimates

Participation estimates should be put in terms of participation rates, measured by dividing efficiency program participants by the total population of customers eligible for the program. Participation rates provide context and more meaningful information relative to a simple number of program participants. Participation rates can also be used to compare participation across programs, across utilities, and across jurisdictions.

Participation rates should be estimated for each year of efficiency resource implementation. They should be compared across several years to indicate the extent to which customers are participating in the programs over time. Participation in multiple programs and across multiple years should be accounted for, and the impacts of participation in multiple efficiency programs by the same customer should be accounted for to the extent possible.

If program participation information is not currently available, it should be collected as soon as possible, so that meaningful estimates can be developed in future years. This type of information is critical for assessing the customer equity issues, and hence the rate impact issues, of efficiency resources.

Many equity concerns driven by rate impacts can be mitigated or even eliminated by promoting widespread customer participation in efficiency programs. Program participation information can be used to ensure that most, and potentially all, customers eventually install efficiency resources of one form or another, and thereby experience net lower bills. Efficiency program administrators could be charged with the responsibility to identify those customers that do not install efficiency resources, and to find ways to reach those customers that have not yet implemented some form of efficiency measure.

C.5 Relationship to the Cost-Effectiveness Analysis

The efficiency resource assessment described in Chapter 3 should provide a comparison of the costs and benefits of certain EE resources. The rate and bill impact analysis should provide an indication of the rate, bill, participation, and equity impacts of those efficiency resources.

Regulators and efficiency planners may wish to consider both analyses to determine whether to invest ratepayer funds in those efficiency resources. This determination could include a qualitative comparison of the trade-offs between cost-effectiveness and rate impacts. For example, regulators and efficiency planners could assess whether any expected long-term rate impacts are warranted in light of the cost-effectiveness results, the bill reductions, and the participation rates.

There is no bright line to determine how to balance these different impacts. Instead, this balance will need to be drawn by efficiency planners, ultimately with guidance and final approval of regulators.

Regulators and efficiency planners may choose to modify proposed efficiency programs or portfolios in order to strike a better balance between cost-effectiveness and equity issues. As noted above, one option would be to expand efficiency programs to include more participants and mitigate equity concerns. Another option would be to shift priority from programs that have low participation rates to those that have higher participation rates.

Utilizing Rate, Bill, and Participant Information

A recent study in Vermont estimated that an aggressive, long-term efficiency strategy would produce an average 7 percent reduction in electric bills (net of rate increases) for the more than 95 percent of residential customers who would be expected to participate in programs. The corresponding average increase in bills would be 4–5 percent for the fewer than 5 percent of customers who would not participate (VT DPS 2014).

The Vermont Public Service Board concluded that the estimated rate impact on that portion of customers was acceptable in light of the reduction in bills for participants and the other benefits of EE (VT PSB 2014).

Decision-makers in different jurisdictions might reach different conclusions regarding whether that trade-off would be worth making. However, they cannot make informed decisions unless they see data in this way.

Appendix D. Glossary of Terms

This manual uses several key terms that have specific meaning in the context of the concepts described here.

Avoided costs, refers to the costs of those electricity and gas resources that are deferred or avoided by the energy efficiency resources being evaluated for cost-effectiveness. The avoided costs are what make up the utility system benefits of EE resources.

Distributed energy resources (DERs), refers to electricity and gas resources that are installed on customers' premises (behind the meter), often to improve customer consumption patterns. These include EE, demand response, distributed generation, storage, plug-in electric vehicles, and more.

Energy efficiency resource, refers to EE technologies, services, measures, or programs funded by, and promoted on behalf of, electricity and gas utility customers.

Impacts, refers to both the costs and the benefits of a supply-side or demand-side resource.

Jurisdiction, refers to states, provinces, utilities, municipalities, or other regions for which EE resources are planned and implemented.

Primary cost-effectiveness test, refers to the cost-effectiveness framework that a jurisdiction most relies upon when choosing the efficiency resources in which to invest ratepayer money.

Regulators/decision-makers, refers to institutions, agents or other decision-makers that are authorized to determine utility resource cost-effectiveness and funding priorities. Such institutions or agents include public utility commissions, legislatures, boards of publicly owned utilities, the governing bodies for municipal utilities and cooperative utilities, municipal aggregator governing boards, and more

Regulatory perspective, refers to the perspective of regulators or other decision makers that oversee efficiency resource investment choices. This perspective is guided by the energy and other applicable policy goals—whether in laws, regulations, organizational policies or other codified forms—under which they operate.

Resource Value Framework, refers to a series of seven steps that can guide any jurisdiction to develop its primary test for assessing EE (and other DERs) cost-effectiveness. The Framework embodies the key principles of cost-effectiveness analyses described in Chapter 1.

Resource Value Test (RVT), refers to the primary cost-effectiveness test that a jurisdiction has developed using the Resource Value Framework. It embodies all of the key principles of cost-effectiveness analyses, and accounts for that jurisdiction's applicable policy goals.

Utility system, refers to all elements of the electricity or gas system necessary to deliver services to the utility's customers. For electric utilities, this includes, generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations. This term refers to any type of utility ownership or management, including investor-owned utilities, publicly-owned utilities, municipal utility systems, cooperatives, etc.

EXHIBIT TW/EM – 17

RESPONSE TO SIERRA CLUB 2-11

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 11 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 11 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 11 (a-b, e-g)

Refer to Schedule 2 of Kesler's testimony. For each of the programs in the Company's plan, please provide all cost-effectiveness results for each of the cost-effectiveness tests used in the state. Please provide the following results for each of the tests:

(a) avoided energy costs ($/MW-hr);
(b) avoided capacity costs ($/kW-yr);
(e) avoided cost of compliance with current and anticipated state and federal environmental regulations;
(f) avoided line losses; and
(g) any other element of avoided costs assumed.

Response:

(a) See Confidential Attachment Staff Set 1-11 (1) (DRK) for the requested information.

(b) See Confidential Attachment Staff Set 1-11 (1) (DRK) for the requested information.

(e) The Company objects to this request as vague and unclear.

(f) The line losses associated with DSM programs are 4.947%.

(g) The Company objects to this request as vague and unclear.

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 11 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Ashwani Vaswani
Manager, Energy Market Quantitative Analysis
and Integrated Resource Planning
Dominion Energy, Inc.

Question No. 11 (c-d)

Refer to Schedule 2 of Kesler's testimony. For each of the programs in the Company's plan, please provide all cost-effectiveness results for each of the cost-effectiveness tests used in the state. Please provide the following results for each of the tests:

c) avoided transmission costs ($/kW-yr);
d) avoided distribution costs ($/kW-yr);

Response:

The avoided transmission and distribution capacity cost rate in the Company's modeling is $51.80/kW-year. Demand response programs were modeled with a transmission credit of $32.93/kW-year. Energy efficiency programs were modeled with both transmission and distribution credits of $51.80/kW-year. The avoided distribution cost was $18.87/kW-year.

EXHIBIT TW/EM – 18

RESPONSE TO SIERRA CLUB 5-9

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fifth Set

The following response to Question No. 9 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 24, 2019 has been prepared under my supervision.

Deanna R. Kesler
Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 9

Refer to the Company's response to Sierra Club 2-11(f). Please confirm whether line losses for transmissions and distribution are included as a benefit in the Company's cost-benefit analyses.

Response:

The effects of line losses are included in the Company's cost-benefit analyses of DSM programs.

EXHIBIT TW/EM – 19

RESPONSE TO SIERRA CLUB 2-12

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 12 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 12 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 12

Refer to the cost-effectiveness analysis of the programs in the Company's proposed DSM Plan:

(a) For each of the proposed programs, please provide any and all estimates of participant non-energy benefits (e.g., safety, health, reduced operations and maintenance costs, and increased productivity) that the Company is aware of, has produced, or has caused to be produced, for its programs or for similar program(s) in other jurisdiction(s). Please provide any and all related reports, documents or workpapers associated with those estimates.

(b) For each of the proposed programs, please indicate any and all participant non-energy benefits that were used in the cost-effectiveness analysis.

(c) If any participant non-energy benefits were not included in the cost-effectiveness analysis, why not?

Response:

The Company objects to this request as overly broad, unduly burdensome and not relevant or reasonably calculated to lead to the production of admissible evidence to the extent it seeks "any and all estimates" and "any and all related reports, documents or workpapers associated with those estimates." The Company further objects to this request to the extent it seeks information regarding "similar program(s) in other jurisdictions(s)." Subject to and notwithstanding these objections, the Company provides the following response. The Company complies with the Commission's Rules on Cost/Benefit tests with respect to consideration of cost-effectiveness of DSM programs in Virginia. The Company does not use any non-energy costs or benefits attributed to participants or the Company in its cost/benefit modeling.

EXHIBIT TW/EM – 20

RESPONSE TO SIERRA CLUB 2-13

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 13 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 13 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 13

Refer to the cost-effectiveness analysis of the programs in the Company's proposed DSM Plan:

(a) For each of the proposed programs, please provide any and all estimates of other resource benefits (e.g., other fuel savings and water savings) that analysis the Company is aware of, has produced, or has caused to be produced, for its programs or for similar program(s) in other jurisdiction(s). Please provide any and all related reports, documents or workpapers associated with those estimates.

(b) For each of the proposed programs, please indicate any and all other resource benefits that were used in the cost-effectiveness analysis. Please provide any and all related reports, documents or workpapers associated with those estimates.

(c) If any other resource benefits were not included in the cost-effectiveness analysis, why not?

Response:

The Company objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of relevant evidence as it seeks "any and all estimates" and "any and all related reports, documents or workpapers associated with those estimates." The Company further objects to this request to the extent it seeks information regarding "similar program(s) in other jurisdictions(s)." Subject to and notwithstanding these objections, the Company provides the following response. The Company complies with the Commission's Rules on Cost/Benefit tests with respect to consideration of cost-effectiveness of DSM programs in Virginia.

EXHIBIT TW/EM – 21

DNV-GL, DOMINION ENERGY EFFICIENCY POTENTIAL STUDY: 2018 TO 2027, OCTOBER 17, 2017, WHICH IS FILED AS ATTACHMENT SIERRA CLUB SET 2-4 (DRK) (3)

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Second Set

The following response to Question No. 4 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

The following response to Question No. 4 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 3, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 4

Please provide any and all analyses that the Company has prepared or utilized regarding the technical, economic or achievable potential for Demand-Side Management for the last four years. Please provide any and all related reports, documents or workpapers associated with those analyses.

Response:

The Company objects to this request as overly broad, unduly burdensome, potentially voluminous, and not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding to the extent it seeks "any and all analyses" and "all related reports, documents or workpapers associated with those analyses" without limitation. The Company further objects to this request to the extent it seeks confidential customer information. Nothwithstanding and subject to the foregoing objections, the Company provides the following response:

See the following attachments for the requested information:

Attachment Sierra Club Set 2-4 (DRK) (1) 2015 Potential Study
Attachment Sierra Club Set 2-4 (DRK) (2) 2015 Potential Study Appendices
Attachment Sierra Club Set 2-4 (DRK) (3) 2017 Potential Study
Attachment Sierra Club Set 2-4 (DRK) (4) 2017 Potential Study Update
Attachment Sierra Club Set 2-4 (DRK) (5) 2017 Potential Study Appendices
Attachment Sierra Club Set 2-4 (DRK) (6) 2017 Planning Matrix

Dominion Energy Efficiency Potential Study: 2018 to 2027

Dominion Energy

Date: October 17, 2017

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Glossary

Achievable potential: The amount of savings that would occur in response to specific program funding and measure incentive levels. Savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention.

Applicability factor: The percentage of the building stock that has a particular type of equipment or for which an efficiency measure applies. For example, the applicability factor for a tankless electric water heater (compared to a base standard electric water heater) is the percentage of homes with electric water heaters. The applicability factor for high-efficiency clothes washers as an electric water heating measure is the percentage of homes with electric water heating that also have a clothes washer. For base measures, this is sometimes referred to as the equipment saturation.

Business-as-usual (BAU): Represents a continuation of current activities or trends. For utility programs, it denotes a scenario in which program marketing and administrative budgets are kept constant in real terms, and incentive levels are kept constant as a percentage of incremental costs.

Base+: Denotes an achievable potential scenario where budgets are maintained as in the BAU scenario, but unlike the BAU scenario all measures that passed the economic screening are included in the analysis, not just measures currently in programs. Added measures receive an incentive level comparable to existing program measures.

Baseline analysis: Characterizes how energy consumption breaks down by sector, building type, and end use.

Base measure: The equipment against which an efficiency measure is compared.

C&I: commercial and industrial.

CBECS: US Energy Information Agency (EIA) Commercial Buildings Energy Consumption Survey

CFL: compact fluorescent lamp.

CDA: Conditional Demand Analysis.

Coincidence factor: Utility coincidence factors are the ratio of actual demand at utility peak to the average demand, as calculated from the load shape. These factors vary by market segment or building type, end use, and by time-of-use period.

Cumulative annual: Savings occurring in a particular year that are due to cumulative program activities over time. For example, if a program installs one high-efficiency widget in year 1 of the program, two in year 2, and five in year 3, the cumulative annual savings in year three would be the savings accruing on all eight surviving units in place in year 3, regardless of what year they were installed. Cumulative annual savings does account for equipment retirement. In the example above, widgets are assumed to have an effective useful life of more than three years. If the equipment in the above example were doohickeys, which only have a two-year effective useful life, the year 1 doohickey would have retired at the end of year 2, so only the units sold in years 2 and 3 would contribute to year 3 cumulative annual savings.

Demand-side management (DSM): An electric system must balance the supply of electricity with the demand for electricity. Demand-side management (DSM) programs focus on managing the demand side of this balance through energy-efficiency and load management.

DOE: US Department of Energy.

Economic potential: The technical potential of those energy conservation measures that are cost effective when compared to supply-side alternatives.

Effective useful life (EUL): A measure of the typical lifetime of an efficiency measure. Technically, it is the age at which half of the units have failed and half survive. In DNV GL's ASSYST™ model, all measures are assumed to remain in place until the end of their effective useful lives and then retire.

End-use energy intensity (EUI): Energy use per unit of building stock having a specific end use. For example, the EUI for commercial electric heating is the amount of electricity used for heating divided by the number of square feet of floor space that are electrically heated. EUI differs from EI in that it accounts for the equipment type's saturation. If the saturation of the equipment type is low, the EUI will be much higher than the EUI.

Energy intensity (EI): Energy use per unit of building stock. For example, the EI for commercial electric heating is the amount of electricity used for heating divided by the total square feet. EI differs from EUI in that it does not account for the saturation of the equipment. If the saturation for the equipment type is low, EI will be much lower than the EUI.

EUI adjustment factor: Because equipment efficiencies can change over time independent of program activities, due to either naturally occurring technological changes or external intervention, such as appliance standards, the efficiency of new equipment may differ from the typical efficiency of the equipment stock. The EUI adjustment factor is the ratio of new standard efficiency equipment's energy use to the average energy use of units in the equipment stock.

Feasibility factor: The fraction of the applicable floor space, or households, that is technically feasible to convert to a DSM technology, from an engineering perspective.

Free rider: A program participant who would have invested in an energy efficiency measure even without the intervention of the program. Free riders add to program costs but do not contribute to net energy savings.

Free-rider energy savings: The subset of naturally occurring energy savings for which the utility pays incentives or provides other program benefits. These savings are included in gross program savings but not in net program savings.

Gross program savings: The total savings for all measures installed under the program, including those that would have been installed even without program intervention (free riders). Gross program savings equals net program savings minus free ridership.

HP: horsepower. A metric for the power of a motor.

HVAC: heating, ventilation, and air conditioning. These space-conditioning measures are often discussed as a group and are referred to by the abbreviation HVAC, usually pronounced H-vac.

Incomplete factor: The fraction of the applicable floor space, or households, that has not yet been converted to the particular energy-efficiency technology.

Incremental cost: The additional cost required to purchase an efficiency measure compared to base equipment.

kW: kilowatts, 1,000 watts. A measure of electric power or electricity demand.

kWh: kilowatt-hour. A measure of electrical energy.

LED: light-emitting diode. LEDs are semiconductor light sources. They have been in use for decades as indicator lights; they are increasingly being used for general-purpose lighting. They are highly efficient compared to incandescent lamps.

Line losses: When electricity is transmitted over the transmission and distribution system, some of the electricity is dissipated as heat due to resistance in the transmission lines or inefficiencies in transformers in the distribution system. As a result, the amount of electricity delivered to consumers is less than the amount produced at the generator. These are referred to as line losses or transmission and distribution losses.

MW: megawatt, one million watts. A measure of electric power or electricity demand.

MWh: megawatt-hour, equal to 1,000 kWh. A measure of electrical energy.

NAICS: The North American Industry Classification System is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.

Naturally occurring energy savings: The amount of savings estimated to occur as a result of normal market forces, that is, in the absence of any utility or governmental intervention.

Net program savings: Program savings above and beyond naturally occurring levels. Net savings exclude free-rider energy savings.

Net-to-gross: The ratio of net program savings to gross program savings.

Program potential: This term is used interchangeably with achievable potential.

RASS: Residential Appliance and Saturation Survey.

RECS: EIA Residential Energy Consumption Survey.

Replace on burnout (ROB): A measure that is installed when the previous equipment reaches the end of its useful life. ROB measures penetrate the market gradually as the existing stock of equipment turns over due to equipment age and eventual failure.

Retrofit: A measure that is installed to achieve energy savings independent of the condition of the existing equipment. This includes measures that affect the energy use of other equipment, such as insulation to reduce heating costs. It also includes replacing equipment with higher efficiency equipment before the end of existing equipment's useful life, for example replacing T12 fluorescent lighting in an office with higher efficiency T8s. Retrofits can be done at any time and therefore have the potential to penetrate the market more quickly than ROB measures.

Technical potential: The savings that would result from complete penetration of all analyzed measures in applications where they were deemed technically feasible, from an engineering perspective.

Technology saturation: A factor that relates the cost units used in the model for a measure to its savings units. For example, the cost of a chiller may be expressed in dollars per ton, though the savings are in kWh per square foot. The technology saturation then represents the number of tons of cooling per square foot.

Time-of-use (TOU) period: The Assyst model can analyze energy use by up to six time-of-use periods. These periods are used to characterize the relationship between energy and peak demand, which varies over both season and time of day, and to capture differences in avoided costs and rates over different time periods. TOU periods usually capture differences between summer/winter and peak/off-peak but can also capture shoulder season, mid-peak, or super peak demand, depending on the needs of a utility.

Total resource cost test (TRC): A benefit-cost test that compares the value of avoided energy production and power plant construction to the costs of energy efficiency measures and the program activities necessary to deliver them. The values of both energy savings and peak-demand reductions are incorporated in the TRC test.

UEC: unit energy consumption.

1 EXECUTIVE SUMMARY

Dominion Energy (Dominion) engaged DNV GL to assess the potential for electric energy (kWh) and demand (kW) savings from company-sponsored demand side management (DSM) programs over a ten-year horizon from 2018 to 2027 in its Virginia service territory. The assessment produced:

- Estimates of the magnitude of potential savings on an annual basis
- Estimates of the costs associated with achieving those savings
- Calculation of the cost-effectiveness of the programs based on the estimates above.

DNV GL used its proprietary model, DSM ASSYST™, to produce these outputs.

DNV GL used data collected under previous studies in 2013 and 2016. Those studies included mail surveys of residential and commercial customers; a residential conditional demand analysis; and review, interpretation, and analysis of data provided to DNV GL by Dominion staff.

1.1 Scope and Approach

This section discusses the scope and approach of the energy efficiency modeling efforts.

1.2 Energy Efficiency Potential

This study estimated three basic types of energy efficiency potential:

- Technical potential: The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
- Economic potential: The technical potential of those energy efficiency measures that are cost-effective when compared to supply-side alternatives.
- Achievable program potential: The amount of savings that would occur in response to specific program funding, marketing, and measure incentive levels. In this study, we looked at the potential available under two funding scenarios: 50% incentives and 75% incentives.[1]

DSM ASSYST™ develops an estimate of naturally occurring savings, i.e., those savings that are projected to result from normal market forces in the absence of any intervention by utility sponsors. These savings are not included in the estimate of achievable program potential.

The method used for estimating potential is a “bottom-up” approach, in which energy efficiency costs and savings are assessed at the customer segment and energy efficiency measure-levels. For cost-effective measures based on the total resource cost (TRC) test, program savings potential was estimated as a function of measure economics, rebate levels, and program marketing and education efforts. The modeling approach was implemented using DNV GL’s DSM ASSYST™ model. This model allows for efficient integration of large quantities of measure, building, and economic data to determine energy efficiency potential.

For this study, DNV GL estimated the results of program efforts under two incentive scenarios. One scenario assumed that 50% of incremental measure costs are paid out by Dominion in customer incentives. The second scenario allowed for incentives covering 75% of incremental measure costs. Program marketing costs were scaled upward across scenarios to reflect increasing program effort, and program administration costs were adjusted across scenarios proportional to achievable program energy savings. These scenarios are

[1] These scenarios reflect the percentage of incremental measure cost that is assumed to be paid in customer incentives.

referenced, respectively, as the "50% scenario" and "75% scenario." Program energy and peak-demand savings, as well as program cost effectiveness, were assessed under both funding scenarios.

1.3 Results

Table 1 presents the overall results of the energy efficiency potential analysis for the 2018-2027 period. All efficiency results include line losses and technical and economic potential includes savings from opt-out/exempt/non-jurisdictional customers, while the program savings estimates do not.[2]

Table 1. Summary of Cumulative Energy Efficiency Savings

Energy Efficiency 2018-2027	Technical Potential	Economic Potential	Program Savings Potential: 75% Incentives	Program Savings Potential: 50% Incentives
Energy Savings (GWh)	24,595	13,768	4,177	3,042
Demand Savings (MW)	6,387	3,622	1,109	772
Program Costs – Real ($Million)			$211,943	$105,039

Key takeaways from this study are as follows:

- Dominion has lower range of achievable potential compared to other potential studies conducted by DNV GL. This is mainly driven by Dominion's low avoided costs, which make a challenging environment for DSM programs and measures to demonstrate cost-effectiveness.

- Compared to the 2014 Dominion potential study conducted by DNV GL, technical and economic potential are lower as proportion of base, while achievable potential shows a modest increase. This is due to more mature programs in the Dominion DSM portfolio and a correspondingly higher level of program awareness, and more years of program data to help calibrate the model at the achievable stage of analysis.

- For residential measures, forecasts of lighting savings are reduced due to the impending federal Energy Independence and Security Act (EISA) standards that go into effect in 2020. However, commercial measures, such as duct testing and sealing, have larger market penetration and are more cost-effective now than compared to 2014. These commercial measures are driving much of the increase in achievable savings across the 50% and 75% incentive scenarios.

1.3.1 Aggregate Base Energy-Efficiency Potential Results

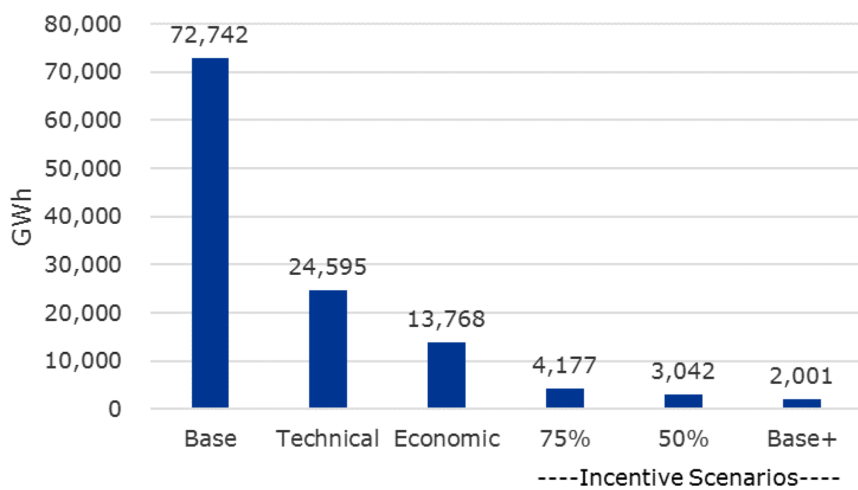
Estimates of electric energy savings potential are presented in Figure 1 below. These savings reflect cumulative annual savings potential over a 10-year period. This can also be looked at as the annual savings potential in 2027 of all installations through 2027. Estimates of energy savings were calculated for Technical Potential, Economic Potential, and three program scenarios, a 75% incentive scenario, a 50% incentive scenario, and a "Base+" scenario that keeps budgets constant but adds in all cost-effective measures, even

[2] Opt-out, exempt, and non-jurisdictional customers do not have to participate in Dominion's DSM programs and were excluded from the program savings analysis accordingly

those not currently in Dominion programs. For the added measures in the Base+ scenario, we applied incentives at a level comparable to current Dominion programs.

Technical potential is estimated at 24,595 GWh per year by 2027. Economic potential is estimated at 13,768 GWh by 2027. Achievable program potentials range from 2,001 GWh in the Base+ scenario[3] up to 4,177 GWh in the 75% incentive scenario. Economic potential for energy savings is estimated to be 19% of base 2027 energy use; achievable potentials range from 3% of base usage in the Base+ case to nearly 6% of base energy use in the 75% incentive case.[4] These results suggest that while obtaining all technical and economic potential will be difficult given Dominion's avoided cost structure, there is additional potential available from measures not currently in Dominion's DSM portfolio. Dominion's past programs have not touched all end uses, so opportunities to start programs targeting those markets.

Figure 1. Estimated Electric Energy-Efficiency Savings Potential, 2018-2027[5]



Cumulative 10-year peak demand savings potential estimates are provided in Figure 2.[6] Technical potential is estimated at 6,387 MW and economic potential is estimated at 3,622 MW. Achievable program potential ranges between 1,109 MW in the 75% incentive case down to 395 MW in the Base+ case. Economic potential for peak demand savings is estimated to be 18% of base 2027 peak demand; achievable potentials range from less than 2% of base peak demand in the Base+ case to 5% of base peak demand in the 75% incentive case. All results include line losses.

[3] Denotes an achievable potential scenario where budgets are maintained at current program levels, but all measures that passed the economic screening are included in the analysis, not just measures currently in programs. Added measures receive an incentive level comparable to existing program measures.

[4] Savings under the 75% incentive scenario are 4% of base non-residential and 8% of residential consumption (excluding base consumption from opt-out/exempt/non-jurisdictional customers). Savings from the 50% scenario are 3% of non-residential and 6% of residential base consumption.

[5] Base use and all potentials exclude opt-out and exempt customers within Dominion's service territory. While technical and economic potentials include savings for non-jurisdictional customers, they were excluded from achievable potential.

[6] The estimates of peak demand savings are from the installation of energy efficiency measures and do not include demand savings from demand response technologies such as direct load control or dynamic pricing.

Figure 2. Estimated Peak Demand Savings Potential, 2018-2027[7]

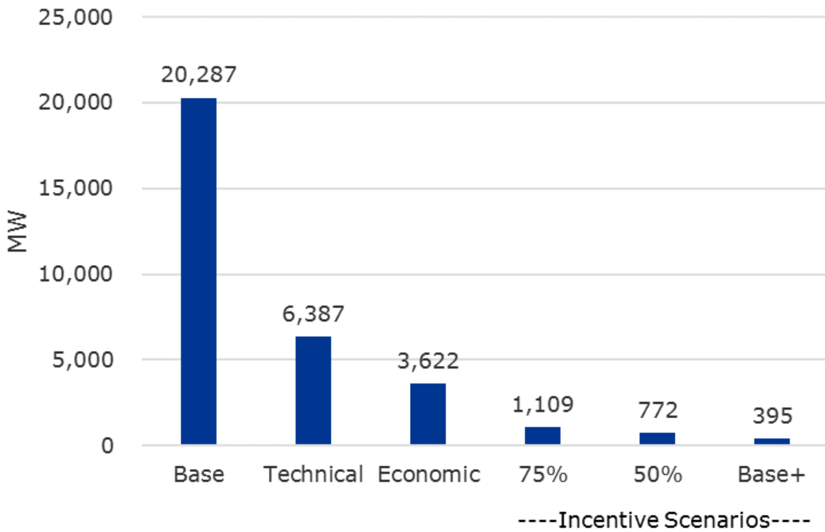


Table 2 compares the results of potential studies recently conducted by DNV GL with the DSM ASSYST™ model.[8,9,10] Achievable energy savings potential as a percent of base consumption available in Dominion's territory is low compared to estimates from other jurisdictions that analyzed savings from 50% and 75% scenarios.

[7] Base use and all potentials exclude opt-out and exempt customers within Dominion's service territory. While technical and economic potentials include savings for non-jurisdictional customers, they were excluded from achievable potential.

[8] Xcel Minnesota: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM/MN-DSM-Market-Potential-Assessment-Vol-1.pdf

[9] Xcel Colorado: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CODSM-Report.pdf

[10] Austin Energy: https://austinenergy.com/wps/wcm/connect/15a83f48-4741-41f9-af6d-ff27a064bd03/2012DSMmarketPotentialAssessment.pdf?MOD=AJPERES

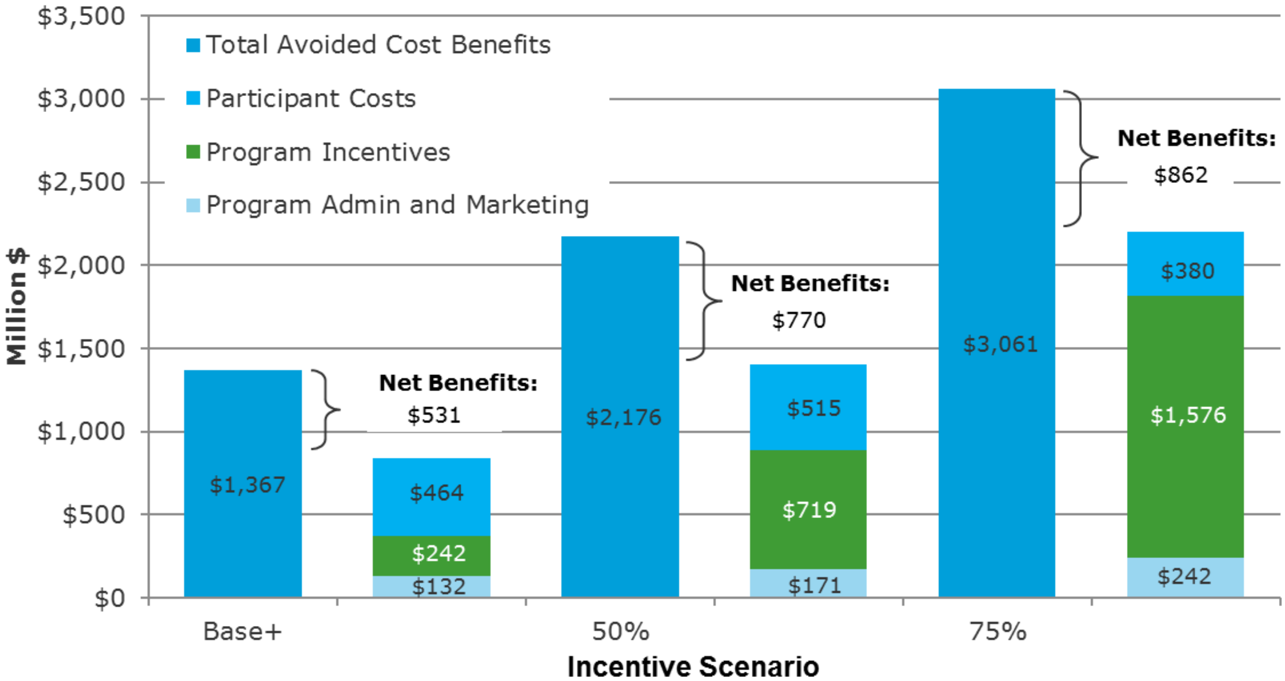
Table 2. Comparison of Energy Savings Potential as a Percent of Base Consumption

Jurisdiction	Years of Analysis	Sectors	Economic Potential	Achievable Potential Scenario	
				50% Incentives	75% Incentives
NGRID	2016-2025		43%	14%	16%
Xcel Min Updated	2014-2023		18%	9%	10%
Dominion	2014-2027	Residential, Non-Residential	22%	3%	6%
Xcel Minnesota	2011-2020	Residential, Commercial, Industrial	20%	10%	11%
Xcel Colorado	2010-2020	Residential, Commercial	23%	5.50%	8.5%
Austin Energy	2012-2020	Residential, Commercial, Industrial	20%		9.8%
Dominion	2018-2027	Residential, Non-Residential	19%	4%	6%

Figure 3 depicts the estimated costs and benefits under each funding scenario from 2018 to 2027. The present value of program costs (including program incentives and program admin and marketing, not including participant costs) is $373 million under the Base+ scenario, $891 million under the 50% scenario, and $1,819 million under the 75% incentive scenario.

The present value of total avoided cost benefits ranges from $1,367 million under Base+ to $3,061 million under 75% incentives. As a result of dramatically increasing incentive costs for higher incentive scenarios, increases in program costs outpace the increases in benefits as one moves to higher incentive scenarios. As modeled, all program participants receive the same incentives in a given scenario, even though some customers would have accepted lower incentives.

Figure 3. Benefits and Costs of Energy Efficiency Savings, 2018-2027*



*PV (present value) of benefits and costs is calculated over the measure life for 2018-2027 program years, customer discount rate = 7.307%, utility discount rate = 6.307%, inflation rate = 1.98%

All funding examined scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness. The TRC benefit-cost ratios for Dominion's service territory are 1.6 for Base+, 1.5 for the 50% scenario, and 1.4 under the 75% scenario.[11] This is a decline in TRC ratios from the previous study, likely due to changes in saturation levels of LED installations, particularly in the residential sector. Key results of our efficiency scenario forecasts from 2018 to 2027 are summarized in Table 3.

[11] This report presents TRC as the cost-benefit test. Under Virginia Law, the RIM, UCT, and PCT are also considered for regulatory approval.

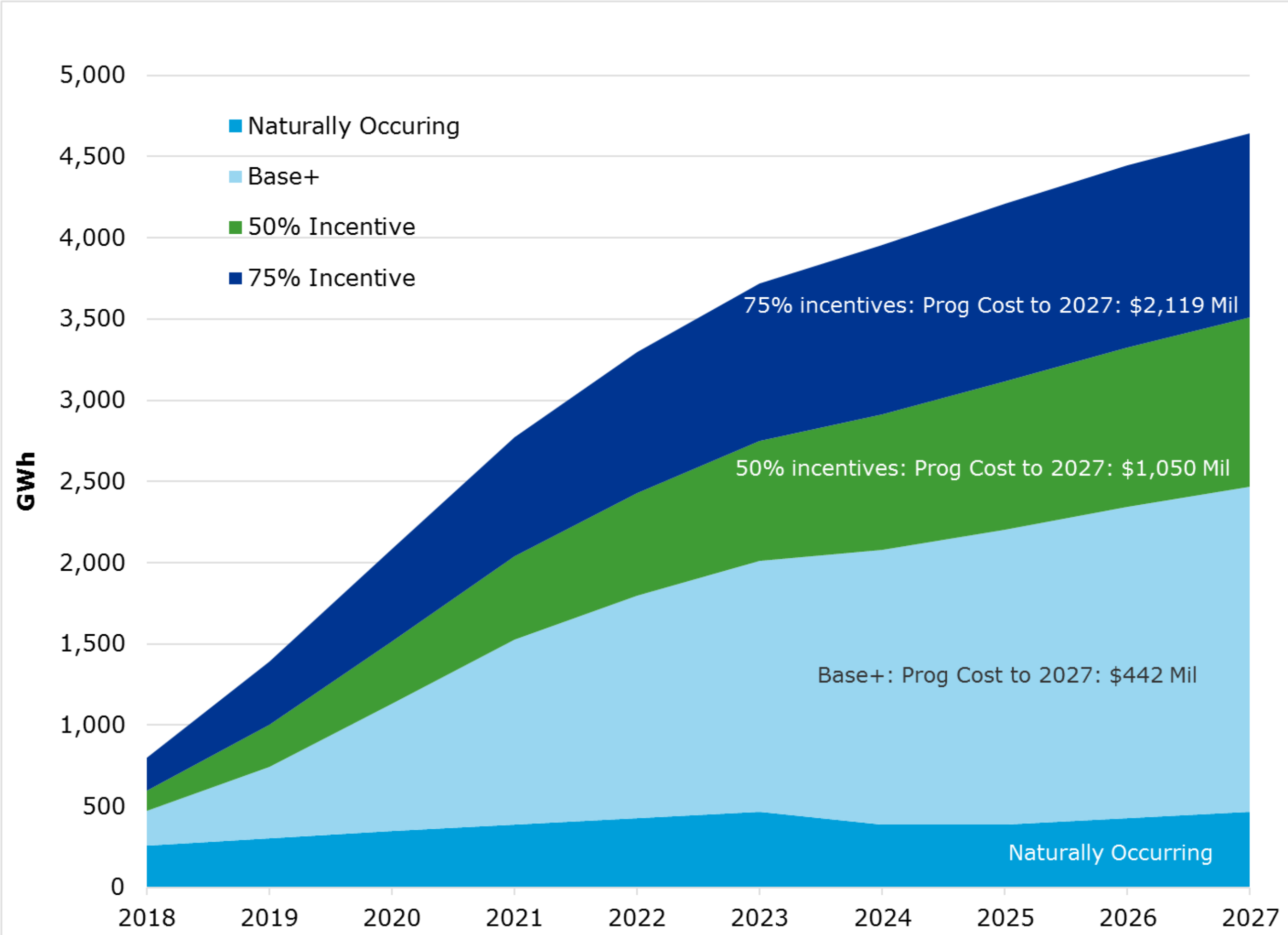
Table 3. Summary of Achievable Potential Results—2018-2027*

Result - Programs	Program Scenario		
	Base+	50% Incentives	75% Incentives
Total Market Energy Savings - GWh	3,081	4,131	5,264
Total Market Peak Demand Savings - MW	578	961	1,298
Program Energy Savings - GWh	2,001	3,042	4,177
Program Peak Demand Savings - MW	395	772	1,109
Program Costs – Real ($Million)			
Administration	$60	$103	$182
Marketing	$96	$101	$106
Incentives	$286	$846	$1,831
Total	**$442**	**$1,050**	**$2,119**
PV Avoided Costs	$1,367	$2,176	$3,061
PV Annual Program Costs (Administrative/Marketing)	$132	$171	$242
PV Net Measure Costs	$705	$1,234	$1,957
Net Benefits	$531	$770	$862
TRC Ratio	1.6	1.5	1.4

*PV (present value) of benefits and costs is calculated over the measure life for 2018-2027 program years, customer discount rate = 7.307%, utility discount rate = 6.307%, inflation rate = 1.98%; GWh and MW savings are cumulative through 2027.

Figure 4 shows estimates of achievable program potential energy savings over time (peak demand savings follow a similar pattern but are not shown). Naturally occurring savings are also shown to provide a picture of total market potential. Savings continue to grow over time, again largely due to a large impact from LEDs in the analysis.

Figure 4. Achievable Electric Energy Savings: All Sectors



1.3.2 Base Energy-Efficiency Results by Sector

Cumulative net achievable potential estimates by sector for the period of 2018-2027 are presented in Figure 5 and Figure 6. These figures compare the residential and non-residential sector results for each funding scenario. All opt-out, exempt, and non-jurisdictional customers were excluded from this analysis.

Under the program assumptions developed for this study, achievable energy and demand savings under the 50% and 75% scenarios are highest for the residential sector.

Figure 5. Net Achievable Energy Savings (2027) by Sector

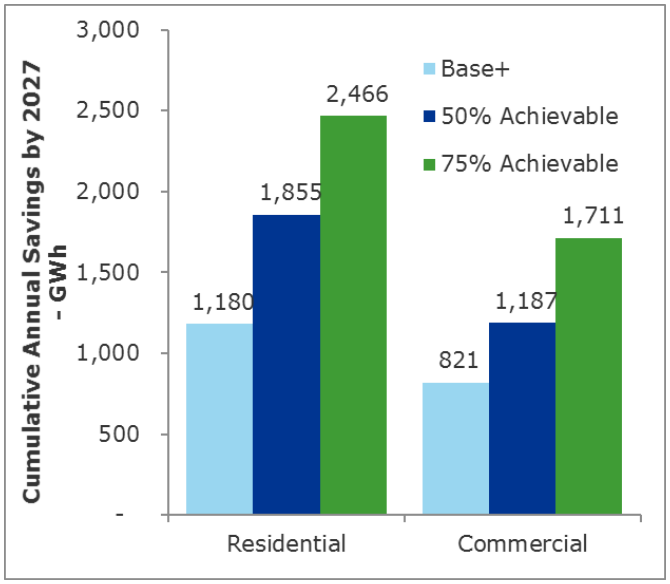
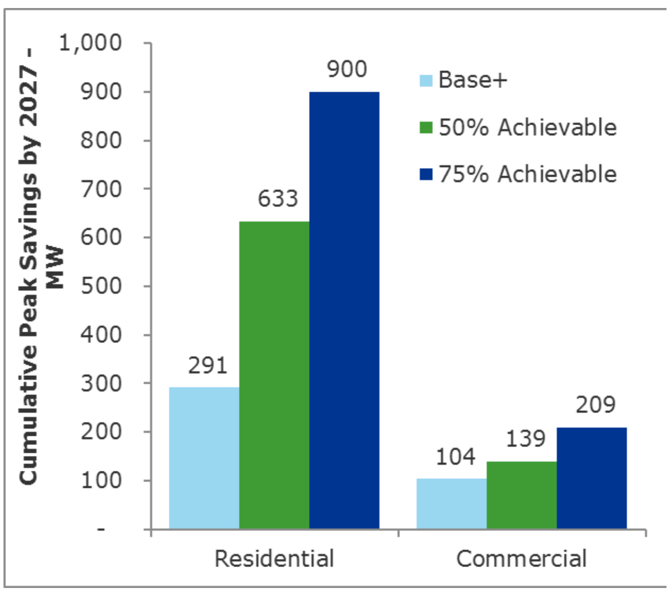


Figure 6. Net Achievable Peak-Demand Savings (2027) by Sector



2 INTRODUCTION

Dominion retained DNV GL to conduct a demand-side management (DSM) market potential study that was based on existing and proposed customer end-use energy efficiency measures and programs. The study provides estimates of potential electricity and peak demand savings from energy efficiency measures in Dominion's Virginia service territory, including technical, economic, and achievable program potential. The analysis also presents the technical and economic potential associated with opt-out, exempt, and non-jurisdictional customers in Dominion's service territory. These customers were not included in the estimation of program achievable potential as they do not participate in Dominion-sponsored programs. The study also does not address natural gas equipment usage or savings.

2.1 Overview

The scope of this study includes new and existing residential and non-residential buildings and covers a 10-year period spanning 2018–2027. Given the near- to mid-term focus, the base potential analysis was restricted to DSM measures that are presently commercially available, and only included codes and standards that are currently in place or will be effective within the next year. We did not make a prediction on the impact of future codes and standards.

Data for the study came from a number of different sources, including: data from the commercial saturation studies conducted by DNV GL in 2013, a residential saturation study conducted by DNV GL in 2016, a residential conditional demand analysis conducted by DNV GL in the 2017, internal Dominion data, DNV GL's extensive energy efficiency database, and a variety of information from third parties.

2.2 Study Approach

2.2.1 Energy-Efficiency Potential Approach

The energy efficiency potential portion of the study involved identifying and developing baseline end-use and measure data, and developing estimates of future energy efficiency impacts under varying levels of program effort.

We performed a baseline characterization that allowed us to identify the types and approximate sizes of the various market segments that are the most likely sources of DSM potential in Dominion's service territory. These characteristics then served as inputs to a modeling process that incorporated Dominion's energy-cost parameters and specific energy efficiency measure characteristics (such as costs, savings, and existing penetration estimates) to provide more detailed potential estimates.

To aid in the analysis, we utilized the DNV GL's DSM ASSYST™ model. This model provides a thorough, clear, and transparent documentation database and an extremely efficient data processing system for estimating technical, economic, and achievable potential. We estimated technical, economic, and achievable program potential for the residential and non-residential sectors, with a focus on energy efficiency impacts through 2027.

2.3 Organization of the Report

Section 3 provides a brief overview of the data collection activities conducted for this study. Full results are provided in a separate report that presents the detailed results of surveys that were conducted to develop the key inputs used in the market potential models. The rest of the report is structured as follows:

- Section 4 discusses the methodology and concepts used to develop the technical, economic, and achievable potential estimates.
- Section 5.1 provides baseline results developed for the study.
- Sections 5.2 and 5.3 discuss the results of the electric energy efficiency potential analysis by sector and over time.

The full report contains the following appendices in a separate document from this report:

- Appendix A: Detailed Methodology and Model Description—Further detail on what was discussed in Section 4.
- Appendix B: Measure Descriptions—Describes the measures included in this study.
- Appendix C: Economic Inputs—Provides avoided cost, electric rate, discount rate, and inflation rate assumptions used for the study.
- Appendix D: Building and TOU Factor Inputs—Shows the base household counts, square footage estimates for non-residential building types, and base energy use by industrial segment. This appendix also includes time-of-use factors by sector and end-use.
- Appendix E: Measure Inputs—Lists the electric measures included in the analysis with the costs, estimated savings, applicability, and estimated current saturation factors.
- Appendix F: Non-Additive Measure Level Results—Shows energy efficiency potential for each measure independent of any other measure.
- Appendix G: Supply-Curve Data—Shows the data behind the energy supply curves provided in Section 5.2.7 of the report.
- Appendix H: Measure-Level Ranking by Economic Energy Savings Potential.
- Appendix I: Achievable Program Potential—Provides the forecasts for the achievable potential scenarios.

3 DATA COLLECTION AND DEVELOPMENT

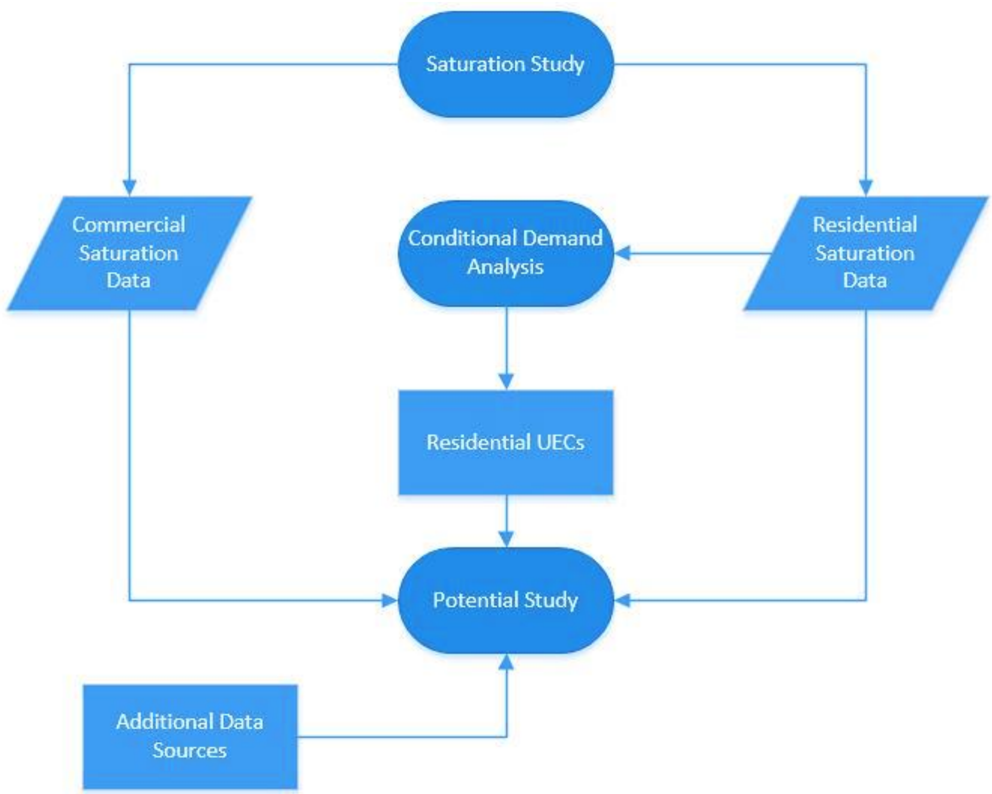
This section describes the efforts used by DNV GL to develop data inputs for this potential study. The main sources of this data were the residential/commercial saturation surveys, the residential conditional demand analysis (CDA), data provided by Dominion staff, and secondary data sources.

3.1 Dominion-Specific Data Collection Efforts

Dominion engaged DNV GL to collect end-use saturation and consumption data from residential and non-residential customers for use in load research and DSM planning operations. Data developed from the resulting studies were also used as direct inputs for the DSM Potential Study. The residential and commercial customer saturation surveys used for these efforts collected information on building characteristics, occupant characteristics, and the penetration and usage of various end uses throughout Dominion's service territory. The residential saturation survey data was then fed into the residential CDA model, which produced estimates of annual electricity consumption for many end-use categories. The CDA estimates, along with data from the saturation studies, were then used as inputs in the DSM ASSYST™ model. These data were combined with other data from Dominion and secondary data sources to fully populate the data inputs required for the modeling effort.

Figure 7 illustrates the relationship between the saturation studies, conditional demand analysis, additional data sources, and the DSM potential study.

Figure 7. Summary Flow Chart for the DSM Potential Study Process



3.1.1 Residential and Commercial Saturation Studies

This 2017 study used the results of the 2016 DNV GL Residential Appliance Saturation Study (RASS) and 2013 DNV GL Commercial Saturation Study. The goal of these studies was to estimate the saturation of end uses of electricity associated with appliances, as well as the usage patterns and related household/building characteristics. The data gathered from these saturation studies fed into the conditional demand analysis which then provided unit energy consumption (UEC) estimates for a range of electric end uses and market segments for the DSM potential study.

The sections below describe the sample selection, data collection and response rates for the residential and commercial saturation studies.

3.1.2 Residential Appliance Saturation Study

3.1.2.1 Sample Selection

The residential saturation study had a final frame of 1,958,352 accounts. DNV GL designed the sample to obtain a specified number of respondents by the following:

- Dominion office
- Multifamily indicator
- Account with an e-mail address indicator
- kWh consumption in last 12 months
- Percent change in weather normalized kWh consumption
- AC Cycling (Residential) participant by AMI indicator by connected load by collapsed region

All saturation estimates developed from this study were correctly weighted so results would apply to the entire target population.

3.1.2.2 Data Collection

Unlike the previous saturation study conducted in 2013, this study was only conducted through an online web survey; in 2013, customers could respond to a mailed survey package or an online survey. In Phase 1, the DNV GL team mailed informative postcards to 12,000 eligible customers and e-mailed another 12,000 customers with information about the online survey. In Phase 2, DNV GL contacted an additional 8,500 eligible customers by e-mail. All respondents were provided with a five-dollar electronic gift card to thank them for their participation.

At completion, 4,206 customers responded to the online survey, 25.7% of which had the multifamily indicator as DNV GL wanted to ensure we collected more responses from this customer group than the 2013 survey. The response rates, by invite mode, are shown in Table 4 on the next page.

3.1.2.3 Response Rates

Unlike the previous saturation study conducted in 2013, this study was only conducted through an online web survey; in 2013, customers could respond to a mailed survey package or an online survey. In Phase 1, the DNV GL team mailed informative postcards to 12,000 eligible customers and e-mailed another 12,000 customers with information about the online survey. In Phase 2, DNV GL contacted an additional 8,500 eligible customers by e-mail. All respondents were provided with a five-dollar electronic gift card to thank them for their participation.

At completion, 4,206 customers responded to the online survey, 25.7% of which had the multifamily indicator as DNV GL wanted to ensure we collected more responses from this customer group than the 2013 survey. The response rates, by invite mode, are shown in Table 4.

Table 4. 2016 Residential Saturation Survey Response Rates

	Total Responses	Final Response Rate
Postcard Invite	1,269	10.6%
Email Invite	2,937	14.5%
Total	4,206	13.0%

3.1.3 Commercial Saturation Study

DNV GL used data from its 2013 Commercial Saturation Study to provide data for this study's commercial sector analysis. The methodology for that data collection effort is described in the report for our 2014 potential study, Dominion Energy Efficiency Potential Study.[12]

3.1.4 Residential Conditional Demand Analysis

The objective of a conditional demand analysis (CDA) is to estimate a breakdown of energy consumption into different end-use categories, such as water heaters or refrigerators, accounting for weather and a number of customer and end-use attributes such as square footage of the home and vintage of the electrical end-use device.

The key data sources for CDA models are:

- Customer survey data – In this study we utilized the RASS conducted by DNV GL in 2016.
- Customer billing data – We merged monthly electricity consumption data from recent years specific to each RASS respondent from Dominion's customer billing database.
- Weather data – We extracted hourly interval temperature data from the National Oceanic and Atmospheric Administration (NOAA) matched to the ZIP codes of RASS respondents.

The methodology develops statistical relationships between these data through regression models. The resulting model estimates are then calibrated to represent a typical meteorological year, rather than using actual weather data from the analysis period, which may have had more mild or extreme weather than normal.

Properly specified CDA models can account for major classes of end uses by residential customers, which include space heating, space cooling, and water heating, among other end uses. Importantly, properly specified CDA models can also produce statistically significant data for end-use combinations.

There are some limiting factors for this CDA model that warrants further discussion, as noted below:

- Near-saturation of the end-use across households (e.g., refrigerators or lighting).
- Co-linearity among certain end uses across households (i.e., groups of two or more types of end uses which are found in those groups more often than individually). For example, set top boxes and TVs together, as opposed to TVs alone.

[12] DNV GL, 2015. Dominion Energy Efficiency Potential Study. Prepared by KEMA, Inc. January, 2015.

- Consumption that is not discernible in monthly billing consumption data among usage behavior variation across households (e.g., printers or toasters).

If some important end-use categories are not typically meaningful to estimate through a CDA alone, they are typically combined with relevant secondary source studies. CDA-based estimates on their own can give valuable insight into end-use consumption distributions across groups of customers.

3.2 Additional Data Sources

In addition to the saturation studies and CDA described above, DNV GL used additional data sources to inform certain inputs of the potential study model that could not be ascertained through the aforementioned data collection efforts. This section outlines those sources, and how they were used in the modeling process. Sources marked with an asterisk (*) in the following section are specific to Dominion's service territory.

3.2.1 Measure Data

Several secondary data sources provided insight on measure-level energy usage and savings potential, measure costs and lifetimes, and the current penetration of various efficiency measures. DNV GL reviewed a variety of data sources for this information with the aim to find data that was specific to Dominion's service territory or geographic location as much as possible. The sources listed below provided information for these inputs:

- EIA Commercial Buildings Energy Consumption Survey (CBECS)
- EIA Residential Energy Consumption Survey (RECS)
- ENERGY STAR® Calculators
- EIA Data for Mid-Atlantic
- Mid-Atlantic Technical Reference Manual (TRM)
- Professional judgment of DNV GL engineers with experience in Dominion's service territory
- Dominion EM&V results

3.2.2 Economic Data

Economic inputs from Dominion's service territory were used to provide a more accurate picture of the monetary cost and benefits associated with energy efficiency. Dominion provided data to support the following model requirements:

- Customer discount rate
- Inflation rate
- Utility discount rate
- Avoided cost and retail rate forecasts for low, base, and high avoided cost scenarios*
- Line-loss estimates

3.2.3 Building Data

Information pertaining to customers as well as system load data was provided by Dominion:

- Billing data to identify consumption residential and commercial customers
- System Load Data
- EIA data for Virginia Electric & Power Co., Virginia to determine number of customers

3.2.4 Program Budgets

As part of the potential modeling process, past and projected program budgets are used to as a starting point for the achievable potential analysis, which estimates the market penetration of measures as a function of marketing, incentive levels, and other factors.[13] Dominion provided past program budgets and savings that we used to help calibrate the achievable modeling efforts. Specifically, marketing and administrative dollars were two inputs into the model that were derived from the indicator tables compiled by DNV GL for Dominion. Table 5 outlines the indicator table data DNV GL reviewed for this effort.

Table 5. DSM EM&V Summary Indicator Tables

Indicator Table Variable Name	Description	DNV GL Funding Designations for Modelling Efforts
Direct Rebate	Dollar value rebates given to participant	
Implementation	Cost of Honeywell/Nexant/Comverge/DOM PM Services	Marketing dollars
Direct EM&V	Cost of DNV GL's EM&V services	Admin dollars
Indirect Other (Administrative)	Shared Dominion services (common costs)	Admin dollars

[13] The methodology of calculation measure penetration is described in more detail in Section 4 and Appendix A

4 ENERGY EFFICIENCY METHODS

4.1 Energy Efficiency Potential Methods

This section provides a brief overview of the concepts, methods, and scenarios used to conduct this study. Additional methodological details are provided in Appendix A.

4.1.1 Characterizing the Energy Efficiency Resource

Energy efficiency has been characterized for some time now as an alternative to energy supply options, such as conventional power plants that produce electricity from fossil or nuclear fuels. In the early 1980s, researchers developed and popularized the use of a conservation supply-curve paradigm to characterize the potential costs and benefits of energy conservation and efficiency. Under this framework, technologies or practices that reduced energy use through efficiency were characterized as making the energy saved available to meet other demands, and could therefore be thought of as a resource and plotted on an energy supply curve. The energy efficiency resource paradigm argued simply that the more energy efficiency or "nega-watts"[14] produced, the fewer new plants would be needed to meet end-users' power demands.

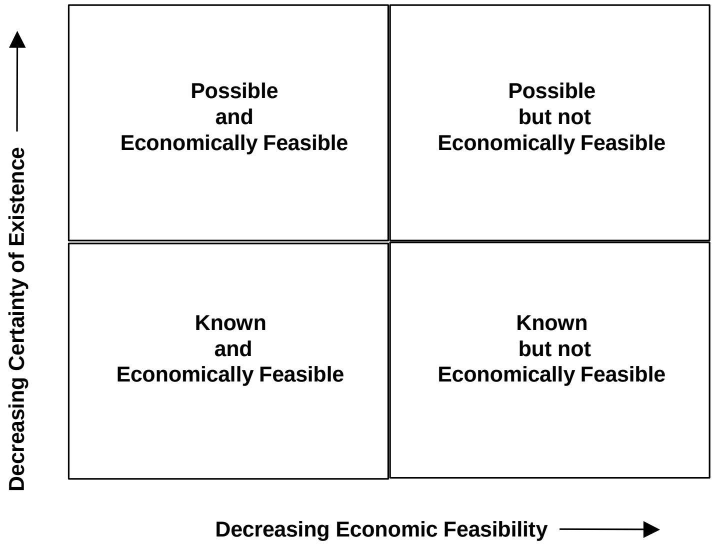
4.1.2 Defining Energy Efficiency Potential

Energy efficiency potential studies became popular throughout the utility industry from the late 1980s through the mid-1990s. This period coincided with the advent of what was called least-cost or integrated resource planning (IRP). Energy efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

Like any resource, there are several ways in which the energy efficiency resource can be estimated and characterized. Definitions of energy efficiency potential are similar to definitions of potential developed for finite fossil fuel resources like coal, oil, or natural gas. For example, fossil fuel resources are typically characterized along two primary dimensions: the degree of geological certainty with which resources may be found, and the likelihood that extraction of the resource will be economic. This relationship is shown conceptually in Figure 8.

[14] Term coined by environmental scientist Amory Lovins in 1989.

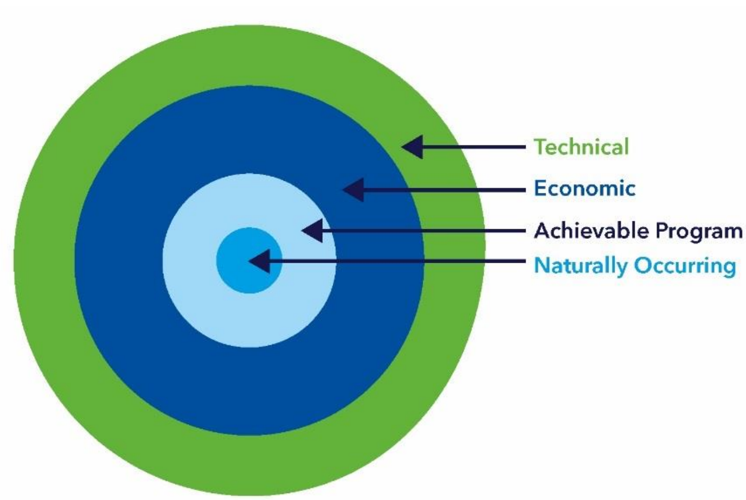
Figure 8. Conceptual Framework for Estimates of Fossil Fuel Resources



Somewhat analogously, this energy efficiency potential study defines several different *types* of energy efficiency *potential*, namely technical, economic, achievable program, and naturally occurring. These potentials are shown conceptually in Figure 9 and described below:

- **Technical potential** is defined in this study as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective.
- **Economic potential** refers to the *technical potential* of those energy conservation measures that are cost effective when compared to supply-side alternatives.
- **Achievable program potential** refers to the amount of savings that would occur in response to specific program funding and measure incentive levels. Savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention.
- **Naturally occurring potential** refers to the amount of savings estimated to occur as a result of normal market forces; that is, in the absence of any utility or governmental intervention.

Figure 9. Conceptual Relationship among Energy Efficiency Potential Definitions



One metric of savings potential that we use is ‘cumulative annual savings.’ These are savings that occur in a year due to program activities from previous years that are still generating energy savings, demonstrated below in a hypothetical example in Table 6. In this example, the Widget Installation Program begins in 2018 and installs energy saving widgets which have a 5-year effective useful life. The following conditions make up the entire scenario:

- In 2018 (Year 1), widgets with total annual savings of 1.00 GWh are installed. There are no previous year program savings, so cumulative annual savings are equal to 2018 savings, or 1.00 GWh.
- In 2019 (Year 2), widgets with total annual savings of 1.50 GWh are installed. Widgets from 2018 are still installed, cumulative annual savings are 2019 *and* 2018 annual savings, or 2.50 GWh.
- In 2020 (Year 3), widgets with total annual savings of 1.75 GWh are installed. Widgets from 2018 and 2019 are still installed, cumulative annual savings are 2020, 2019, *and* 2018 annual savings, or 4.25 GWh.
- In 2023 (Year 6), widgets with total annual savings of 1.75 GWh are installed. Widgets from previous years are still installed. However, in Year 6 the widgets from Year 1 have passed their 5-year effective useful life and are no longer generating energy savings. Cumulative annual savings include savings from widgets installed in 2023, 2022, 2021, 2020, and 2019, *but not* those installed in 2018.

Cumulative annual savings account for equipment retirement; it is a performance metric and not an accounting metric. In the example, widgets are assumed to have an effective useful life of five years; 2023 savings include those measures generating savings in 2023 and do not include 2018 installations which have passed their effective useful life. Cumulative Annual Savings are often confused with what we can call “Total Accounting Savings.”

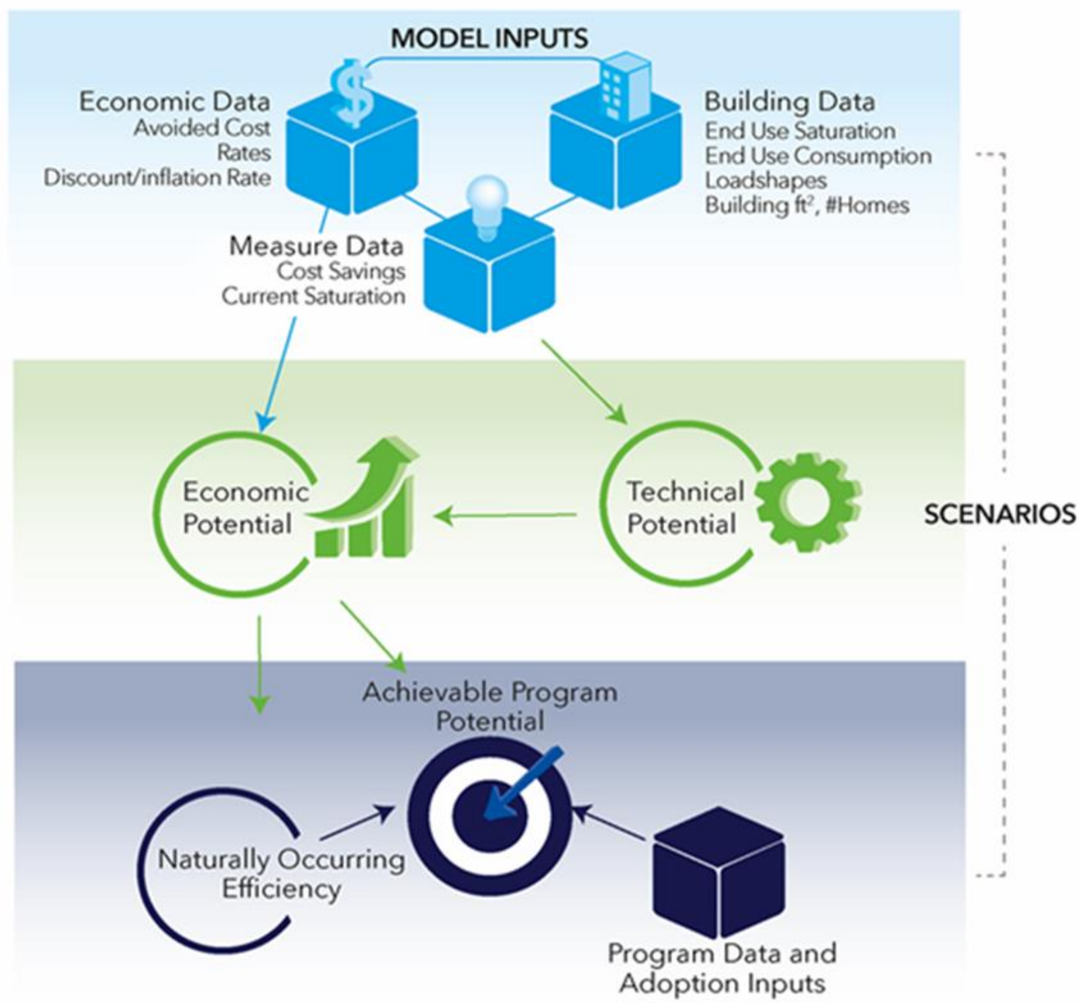
Table 6. Example of Cumulative Annual Savings for Widget Installation Program

Installation Year	Energy Savings Year (GWh)									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
2018	1.00	1.00	1.00	1.00	1.00					
2019		1.50	1.50	1.50	1.50	1.50				
2020			1.75	1.75	1.75	1.75	1.75			
2021				1.75	1.75	1.75	1.75	1.75		
2022					1.75	1.75	1.75	1.75	1.75	
2023						1.75	1.75	1.75	1.75	1.75
2024							1.50	1.50	1.50	1.50
2025								1.25	1.25	1.25
2026									1.00	1.00
2027										0.50
Cumulative Annual Savings (GWh)	**1.00**	**2.50**	**4.25**	**6.00**	**7.75**	**8.50**	**8.5**	**7.00**	**7.25**	**6.00**
Total Accounting Savings (GWh)	**1.00**	**3.50**	**7.75**	**13.75**	**21.50**	**30.00**	**38.50**	**45.50**	**52.75**	**58.75**

4.1.3 Summary of Analytical Steps Used to Calculate Energy Efficiency Potential

The crux of this study involves carrying out several basic analytical steps to produce estimates of the energy efficiency potentials introduced above. The basic analytical steps for this study are shown in relation to one another in Figure 10. The bulk of the analytical process for this study was carried out in a model developed by DNV GL for conducting energy efficiency potential studies. Details on the steps employed and analyses conducted are described in Appendix A. The model used DSM ASSYST™, a Microsoft® Excel-based model that integrates technology-specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system.

Figure 10. Conceptual Overview of Study Process



The key steps implemented in this study are:

1. Develop Initial Input Data
    - Develop a list of energy efficiency measure opportunities to include in scope. In this step, an initial draft measure list was developed and provided to Dominion. The final measure list was developed after incorporating comments.
    - Gather and develop technical data (costs and savings) on efficient measure opportunities. Data on measures were gathered from a variety of sources. Measure descriptions are provided in Appendix B and detail on measure inputs is provided in Appendix E.
    - Gather, analyze, and develop information on building characteristics, including total square footage or total number of households, energy consumption and intensity by end use, end-use consumption load patterns by time of day and year (i.e., load shapes), market shares of key electric consuming equipment, and market shares of energy efficiency technologies and practices. Section 5.1.1 of this report describes the baseline data developed for this study.
    - Collect data on economic parameters: avoided costs, electricity rates, discount rates, and inflation rate. These inputs are provided in Appendix C of this report.
2. Estimate Technical Potential and Develop Supply Curves
    - Match and integrate data on efficient measures to data on existing building characteristics to produce estimates of technical potential and energy efficiency supply curves.
3. Estimate Economic Potential
    - Match and integrate measure and building data with economic assumptions to produce indicators of costs from different viewpoints (e.g., societal and consumer).
    - Estimate total economic potential. (Note that at this stage of the analysis, program-related costs are not factored into the cost-effectiveness screening. Thus, the results reflect the theoretical estimate of the measure impacts, while disregarding the mode of delivery.)
4. Estimate Achievable Program and Naturally Occurring Potentials
    - Screen initial measures for inclusion in the program analysis. This screening may take into account factors such as cost effectiveness, potential market size, non-energy benefits, market barriers, and potentially adverse effects associated with a measure. For this study, measures were screened using the total-resource-cost test, with the exclusion of program costs and while considering only electric avoided-cost benefits.
    - Gather and develop estimates of program costs (e.g., for administration and marketing) and historic program savings.
    - Develop estimates of customer adoption of energy efficiency measures as a function of the economic attractiveness of the measures, barriers to their adoption, and the effects of program intervention.
    - Estimate achievable program and naturally occurring potentials and associated program costs.
5. Scenario Analyses
    - Recalculate potentials under alternate program scenarios.

5 ENERGY EFFICIENCY RESULTS

5.1 Energy Efficiency Baseline Analysis

This section presents a baseline analysis of energy use in Dominion's Virginia service territory. The purpose of this analysis is to provide a breakout of energy use by sector, building type and end use to provide a foundation for estimating demand side management /energy efficiency potentials.

DNV GL completed a conditional demand analysis of the residential sector using the saturation survey results and billing data to develop energy consumption values for various end uses. That data was incorporated into this analysis.

The non-residential analysis was not affected by the conditional demand analysis and is based on the best data available. However, in some cases we used regional data, such as South Atlantic Census Division data from the US Department of Energy (DOE) Commercial Buildings Energy Consumption Survey (CBECS), rather than those specific to Dominion's service territory. It was necessary to rely on such sources for inputs that could not be determined from the commercial survey data or from other Dominion data sources.

5.1.1 Summary of Baseline Energy Use by Sector

Energy usage by sector and business type was developed from data reported by the US Energy Information Administration (EIA). These data are presented in Table 7.

Table 7. Summary of Dominion MWh and Customers by Sector [15]

Sector	MWh	# of Customers
Residential	29,293,300	2,150,818
Non-Residential	46,731,511	254,445
Total	76,024,811	2,405,263

Source: EIA, data for Virginia Electric & Power Co., Virginia, 2012, 2015

Note that these values include non-jurisdictional, exempt, and opt-out customers, and industrial customers. Exempt and opt-out customers will be broken out later. Industrial customers are not part of the potential study and will be excluded from the rest of the analysis.

5.1.2 Residential Baseline

EIA data[16] for Virginia was used to group total residential customers into single-family and multifamily customers, the two residential segments being examined in this study. Table 8 shows the results.

Table 8. Number of Residential Customers by Building Type

Building Type	# of Customers	Percent of Housing
Single Family	1,786,660	83%
Multifamily	364,158	17%
Total	2,150,818	100%

[15] As available at https://www.eia.gov/electricity/data.php#sales, Tables 6-10

[16] EIA, 2009. Household Energy Use in Virginia. Summary of state level data from the 2009 Residential Energy Consumption Survey.

5.1.2.1 Residential End-Use Saturations

The equipment saturations (percent of households having an end use) were calculated from the results of the residential saturation surveys. These results are shown in Table 9. For lighting, the equipment saturations interact with the number of lamps per home by usage and type. For modeling simplicity, the assumption is 100% saturation for each of the lighting wattage/use breakouts, with all the variation between homes being captured through the number of lamps per home for each lighting category.

Table 9. Residential End-Use Saturations by Base Measure

End-use Saturations	Single Family	Multifamily
Base Split-System Air Conditioner	42%	42%
Base Early Replacement Split-System Air Conditioner	12%	7%
Base Heat Pump Cooling	34%	41%
Base Early Replacement Heat Pump Cooling	6.9%	2.5%
Base Room Air Conditioner	2.1%	6.2%
Base Early Replacement Room Air Conditioner	0.3%	0.0%
Base Dehumidifier	32%	10%
Base Furnace Fans	95%	93%
Base Heat Pump Space Heating	37%	39%
Base Early Replacement Heat Pump Heating	5.3%	4.2%
Base Resistance Space Heating (Primary)	12%	30%
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	100%	100%
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	100%	100%
Base High-Efficiency Incandescent Lighting, 6 hrs/day	100%	100%
Base Lighting 15 Watt CFL, 0.5 hrs/day	100%	100%
Base Lighting 15 Watt CFL, 2.5 hrs/day	100%	100%
Base Lighting 15 Watt CFL, 6 hrs/day	100%	100%
Base Lighting 9 Watt LED, 0.5 hrs/day	100%	100%
Base Lighting 9 Watt LED, 2.5 hrs/day	100%	100%
Base Lighting 9 Watt LED, 6 hrs/day	100%	100%
Base Specialty Incandescent Lighting, 0.5 hrs/day	100%	100%
Base Specialty Incandescent Lighting, 2.5 hrs/day	100%	100%
Base Specialty Incandescent Lighting, 6 hrs/day	100%	100%
Base Fluorescent Fixture 1.8 hrs/day	100%	100%
Base Refrigerator	78%	80%
Base Early Replacement Refrigerator	22%	20%
Base Second Refrigerator	40%	5%
Base Freezer	21%	13%
Base Early Replacement Freezer	14%	3%
Base Second Freezer	2.8%	0.1%
Base 40 gal. Water Heating	24%	15%
Base Early Replacement Water Heating	31%	55%

End-use Saturations	Single Family	Multifamily
Base Clothes washer	100%	89%
Base Clothes Dryer	91%	85%
Base Dishwasher	90%	82%
Base Pool Pump	5.5%	0.0%
Base Plasma TV	18%	13%
Base LCD TV	87%	82%
Base CRT TV	18%	14%
Base Set-Top Box	84%	83%
Base DVD Player	85%	65%
Base Desktop PC	62%	29%
Base Laptop PC	83%	85%
Base Cooking	74%	70%
Base Miscellaneous	100%	100%

An initial estimate of the number of incandescent lamps, CFLs, and LEDs per home was made using the survey data. These self-reported data suggested a total of 27 lamps per single family home and 12 lamps per multifamily home in Virginia. These values seem low when compared to lighting studies from other regions and the reported size of the homes. Self-reported values tend to underestimate lamp counts compared to on-site studies, since residents tend to forget about lamps used infrequently. The results of the conditional demand analysis (CDA) also suggested that the number of lamps was likely understated, since the lighting energy use from the CDA combined with the reported number of lamps implied an extremely high kWh usage per lamp—either very high wattage or very high average usage (or both). As a result of these concerns, when the model was calibrated so that lighting energy use would match the CDA results, the number of lamps per home was increased above the values found in the survey.

Also, to align the lighting saturation information with the lighting methodology used in DSM ASSYST™, the number of lamps was broken out into usage bins, as available from internal DNV GL databases (gleaned from previous potential studies and on-site data collection). The resulting breakouts are shown in Table 10.

Table 10. Lamps per Home by Type and Usage

Lamp Type	Single Family	Multifamily
Incandescent, 0.5 hrs/day	13.4	5.5
Incandescent, 2.5 hrs/day	9.6	3.9
Incandescent, 6 hrs/day	2.3	1.1
CFL, 0.5 hrs/day	6.7	3.5
CFL, 2.5 hrs/day	5.5	2.9
CFL, 6 hrs/day	1.5	0.8
Specialty Incandescent, 0.5 hrs/day	1.7	1.7
Specialty Incandescent, 2.5 hrs/day	2.9	2.1
Specialty Incandescent, 6 hrs/day	1.2	0.4
Fluorescent Fixture 1.8 hrs/day	6.2	1.9

Lamp Type	Single Family	Multifamily
Total	64.5	27.9

5.1.2.2 Residential End-Use Energy Intensities

Table 11 shows the end-use energy intensities for the residential sector by base measure. End-use energy intensities represent the energy use per household for households that have that end-use. Most of these energy intensity values were derived from the conditional demand analysis. The rest were derived or calculated from a variety of sources, including:

- DOE's Home Energy Saver model
- The US Environmental Protection Agency (EPA) ENERGY STAR calculators
- Engineering calculations (for lighting).

Table 11. Residential End-Use Energy Intensities (kWh/household with end-use)

kWh/household	Single Family	Multifamily
Base Split-System Air Conditioner	3,232	1,593
Base Early Replacement Split-System Air Conditioner	3,820	1,644
Base Heat Pump Cooling	2,917	1,666
Base Early Replacement Heat Pump Cooling	2,963	1,969
Base Room Air Conditioner	2,541	881
Base Early Replacement Room Air Conditioner	1,326	0
Base Dehumidifier	900	369
Base Furnace Fans	1,143	475
Base Heat Pump Space Heating	4,141	1,554
Base Early Replacement Heat Pump Heating	6,753	2,819
Base Resistance Space Heating (Primary)	3,133	1,176
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	93	46
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	332	164
Base High-Efficiency Incandescent Lighting, 6 hrs/day	190	115
Base Lighting 15 Watt CFL, 0.5 hrs/day	17	10
Base Lighting 15 Watt CFL, 2.5 hrs/day	70	40
Base Lighting 15 Watt CFL, 6 hrs/day	46	27
Base Lighting 9 Watt LED, 0.5 hrs/day	3	3
Base Lighting 9 Watt LED, 2.5 hrs/day	24	17
Base Lighting 9 Watt LED, 6 hrs/day	23	8
Base Specialty Incandescent Lighting, 0.5 hrs/day	79	24
Base Specialty Incandescent Lighting, 2.5 hrs/day	323	98
Base Specialty Incandescent Lighting, 6 hrs/day	213	67
Base Fluorescent Fixture 1.8 hrs/day	442	121
Base Refrigerator	749	549
Base Early Replacement Refrigerator	900	626
Base Second Refrigerator	1,018	452

kWh/household	Single Family	Multifamily
Base Freezer	701	493
Base Early Replacement Freezer	804	733
Base Second Freezer	489	252
Base 40 gal. Water Heating	3,830	1,721
Base Early Replacement Water Heating	3,452	2,140
Base Clothes washer	44	39
Base Clothes Dryer	757	670
Base Dishwasher	247	221
Base Pool Pump	811	811
Base Plasma TV	194	193
Base LCD TV	213	127
Base CRT TV	49	42
Base Set-Top Box	262	173
Base DVD Player	36	27
Base Desktop PC	438	365
Base Laptop PC	64	44
Base Cooking	895	888
Base Miscellaneous	600	500
Base House Practices	15,083	8,330

5.1.2.3 Water Heating End-Use Energy Intensities

Water heating energy use was broken into several components in the CDA. The first and largest component was base water heating, which did not include weather (heating degree day, or HDD), dependent water heating, or the water heating associated with clothes washers and dishwashers (which was included with the energy use for those appliances). The components produced by the CDA are shown in Table 12.

Table 12. Water-Heating-Related Outputs of the CDA Model

CDA Component	Description	Values
Base water heating	Water heating only. Corresponds to summer usage, excluding water heating associated with clothes washers and dishwashers	2,130 kWh per single family household and 1,373 per multifamily household*
Clothes Washers (including both machine energy and associated water heating)	Energy use attributable to clothes washers, including both the energy used by the machine and the associated water heating	141 kWh per single family household and 139 per multifamily household*
Dishwashers (including both machine energy and associated water heating)	Energy use attributable to dishwashers, including both the energy used by the machine and the associated water heating	92 kWh per single family household and 91 per multifamily household*
Water Heating (HDD-dependent)	This includes the portion of water heating energy that increases as temperatures get colder, reflecting both increased storage losses and increased usage	1,583 kWh per single family household and 956 per multifamily household*

*For households with the end use

For the baseline analysis, the water heating energy for the two appliances needed to be split apart from machine energy and included with the rest of water heating. To do this, data had to be pulled in from other sources. The HDD-dependent water heating needed to be included with the rest of water heating as well.

For its appliance standard-setting process, the DOE performs detailed energy analyses, which are published in technical support documents.[17] Using the data from these analyses and calibrating between DOE's estimated total energy use for each appliance, and the total energy use for each from the CDA, produced estimates of 46 kWh of machine energy for clothes washers and 260 kWh of machine energy for dishwashers. The clothes washer value is consistent with total CDA energy use, so the machine energy was netted out of the appliance totals to estimate the water heating portion of energy. The water heating share was then weighted by appliance saturations by state and building type (since not all homes with electric water heating have clothes washers) and the result was added to the base water heating energy.

The DOE estimate of dishwasher energy, on the other hand, is higher than the total CDA estimate. Because CDA's produce less reliable estimates of energy use when saturations are close to 100%, and the dishwasher saturation for single family households was above 90%, we believed the DOE value for machine energy was more reliable. We used the DOE value for machine energy and assumed that dishwasher water heating energy had already been captured in the baseload water heating estimate (that is, none of the dishwasher energy from the CDA was reassigned to water heating).

Table 13 shows the resulting appliance-related water heating energy, with the CDA estimates of base water heating and HDD-dependent water heating energy. Total water heating energy ranges from 2,411 to 3,808 kWh, depending on building type.

[17] These are available online at http://energy.gov/eere/buildings/standards-and-test-procedures.

Table 13. Water Heating Household Energy Use (kWh) by Component

	Single Family	Multifamily	All Homes
Water heating base energy use	2,130	1,373	2,002
Saturation-weighted CW/DW water heating energy	171	117	162
HDD-dependent water heating	1,583	956	1,477
Total	3,808	2,411	3,571

5.1.2.4 Residential Energy Use

Energy use was calculated as the product of the number of households, equipment saturation, and the end-use energy intensity. Energy use by building type and end-use is shown in Table 14.

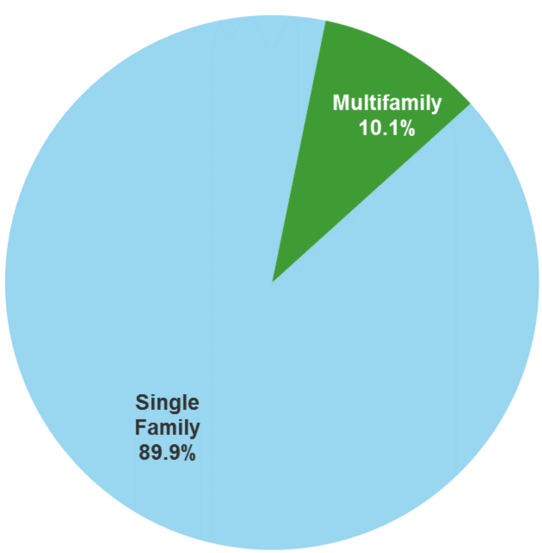
Table 14. Residential Energy Use by Building Type and End-Use

	Single Family	Multi-Family	Total
Base Split-System Air Conditioner (13 SEER)	2,403,966	242,596	2,646,562
Base Early Replacement Split-System Air Conditioner (11 SEER)	840,329	44,569	884,897
Base Heat Pump Cooling (13 SEER)	1,780,952	250,224	2,031,177
Base Early Replacement Heat Pump Cooling (11 SEER)	363,230	17,898	381,128
Base Room Air Conditioner - EER 10.6	96,961	19,992	116,953
Base Early Replacement Room Air Conditioner- EER 9.7	7,465	-	7,465
Base Dehumidifier (40 pints/day, 1.5 liters/kWh)	512,913	13,707	526,619
Base Furnace Fans	1,939,084	161,028	2,100,113
Base Heat Pump Space Heating (7.7 HSPF)	2,728,581	222,184	2,950,765
Base Early Replacement Heat Pump Heating (11 SEER)	639,338	42,978	682,316
Base Resistance Space Heating (Primary)	672,626	126,834	799,460
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	166,743	16,926	183,669
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	593,987	59,774	653,762
Base High-Efficiency Incandescent Lighting, 6 hrs/day	338,962	41,944	380,906
Base Lighting 15 Watt CFL, 0.5 hrs/day	30,520	3,525	34,044
Base Lighting 15 Watt CFL, 2.5 hrs/day	125,349	14,686	140,034
Base Lighting 15 Watt CFL, 6 hrs/day	82,839	9,692	92,532
Base Lighting 9 Watt LED, 0.5 hrs/day	5,078	1,008	6,086
Base Lighting 9 Watt LED, 2.5 hrs/day	42,317	6,302	48,618
Base Lighting 9 Watt LED, 6 hrs/day	40,624	3,025	43,649
Base Specialty Incandescent Lighting, 0.5 hrs/day	140,475	8,818	149,293
Base Specialty Incandescent Lighting, 2.5 hrs/day	576,951	35,609	612,560
Base Specialty Incandescent Lighting, 6 hrs/day	381,290	24,418	405,707
Base Fluorescent Fixture 1.8 hrs/day	790,401	43,893	834,294
Base Refrigerator	1,039,381	159,522	1,198,903
Base Early Replacement Refrigerator	356,695	45,796	402,491

	Single Family	Multi-Family	Total
Base Second Refrigerator	723,969	8,289	732,258
Base Freezer	268,765	22,961	291,726
Base Early Replacement Freezer	197,005	7,555	204,560
Base Second Freezer	24,301	85	24,386
Base 40 gal. Water Heating (EF=0.88)	1,643,795	94,985	1,738,780
Base Early Replacement Water Heating to Heat Pump Water Heater	1,913,275	428,238	2,341,513
Base Clothes Washer (MEF=1.26)	78,764	12,744	91,509
Base Clothes Dryer (EF=3.01)	1,233,950	207,694	1,441,644
Base Dishwasher (EF=0.65)	395,528	65,727	461,255
Base Pool Pump (RET)	79,795	-	79,795
Base Plasma TV	61,981	8,826	70,807
Base LCD TV	330,783	37,912	368,695
Base CRT TV	15,765	2,177	17,942
Base Set-Top Box	395,086	52,423	447,509
Base DVD Player	55,155	6,369	61,525
Base Desktop PC	488,924	39,073	527,997
Base Laptop PC	95,427	13,628	109,055
Base Cooking	1,177,814	224,694	1,402,508
Base Miscellaneous	1,071,996	182,079	1,254,075
Base House Practices	26,949,135	3,032,406	29,981,540
Total	26,949,135	3,032,406	29,981,540

Figure 11 shows the breakout of residential energy use by building type and end use, respectively.

Figure 11. Residential Energy Use by Building Type



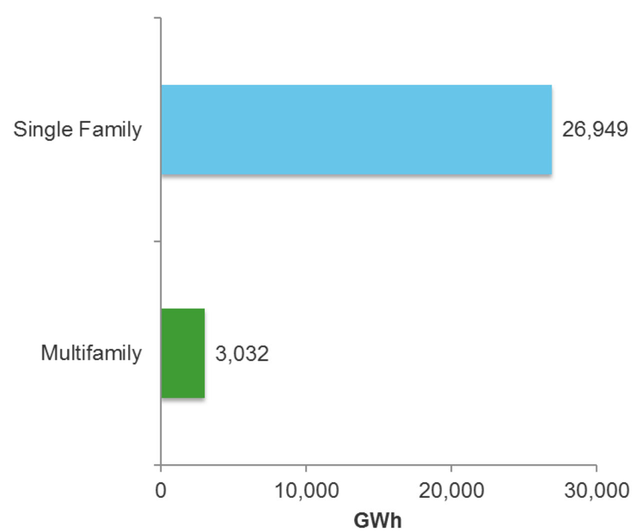
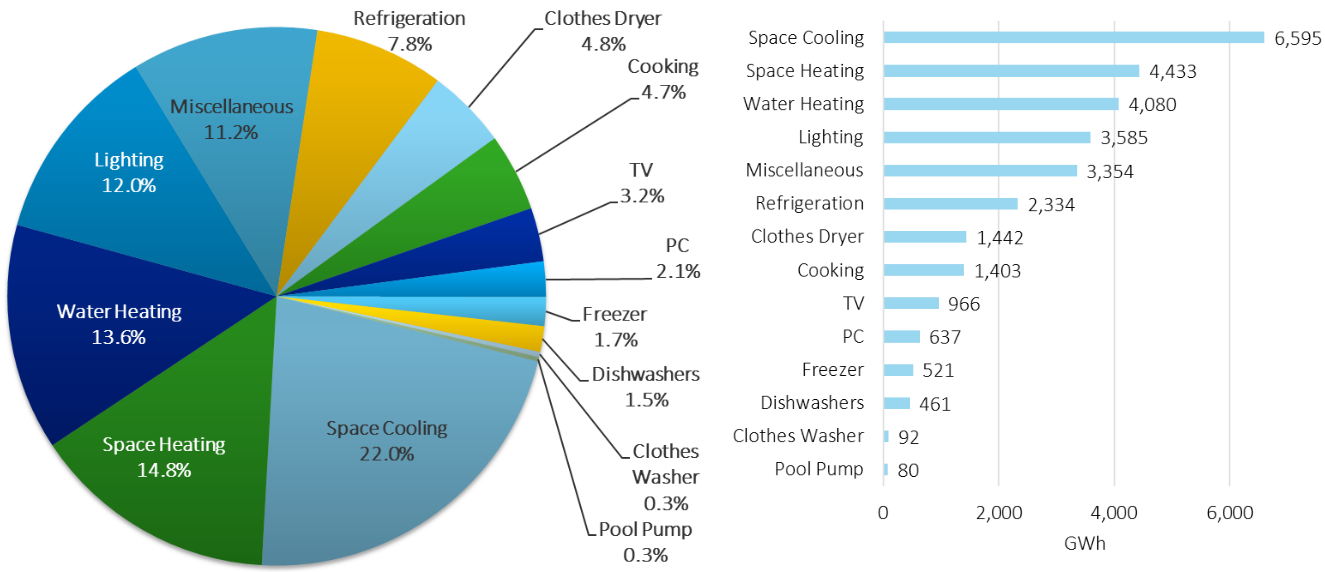


Figure 12. Residential Energy Use by End-Use



5.1.2.5 Residential Peak Demand

Annual 8,760 hourly data from Dominion was combined with end-use load shape data from DNV GL's end-use databases to allocate annual energy usage into time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, was calibrated to equal the Dominion summer peak. Residential peak demand estimates by segment and end use are summarized in Table 15.

Table 15. Summary of Residential Electric Peak Demand by Segment and End Use (MW)

	Single Family	Multifamily	Total
Base Split-System Air Conditioner (13 SEER)	1,298	131	1,429
Base Early Replacement Split-System Air Conditioner (11 SEER)	454	24	478
Base Heat Pump Cooling (13 SEER)	962	135	1,097
Base Early Replacement Heat Pump Cooling (11 SEER)	196	10	206
Base Room Air Conditioner - EER 10.6	52	11	63
Base Early Replacement Room Air Conditioner- EER 9.7	4	0	4
Base Dehumidifier (40 pints/day, 1.5 liters/kWh)	61	2	63
Base Furnace Fans	936	78	1,013
Base Heat Pump Space Heating (7.7 HSPF)	294	24	318
Base Early Replacement Heat Pump Heating (11 SEER)	69	5	74
Base Resistance Space Heating (Primary)	73	14	86
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	17	2	19
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	60	6	67

	Single Family	Multifamily	Total
Base High-Efficiency Incandescent Lighting, 6 hrs/day	34	4	39
Base Lighting 15 Watt CFL, 0.5 hrs/day	3	0	3
Base Lighting 15 Watt CFL, 2.5 hrs/day	13	1	14
Base Lighting 15 Watt CFL, 6 hrs/day	8	1	9
Base Lighting 9 Watt LED, 0.5 hrs/day	1	0	1
Base Lighting 9 Watt LED, 2.5 hrs/day	4	1	5
Base Lighting 9 Watt LED, 6 hrs/day	4	0	4
Base Specialty Incandescent Lighting, 0.5 hrs/day	14	1	15
Base Specialty Incandescent Lighting, 2.5 hrs/day	59	4	62
Base Specialty Incandescent Lighting, 6 hrs/day	39	2	41
Base Fluorescent Fixture 1.8 hrs/day	80	4	85
Base Refrigerator	153	24	177
Base Early Replacement Refrigerator	53	7	59
Base Second Refrigerator	107	1	108
Base Freezer	39	3	42
Base Early Replacement Freezer	28	1	29
Base Second Freezer	3	0	4
Base 40 gal. Water Heating (EF=0.88)	184	11	195
Base Early Replacement Water Heating to Heat Pump Water Heater	214	48	262
Base Clothes Washer (MEF=1.26)	13	2	15
Base Clothes Dryer (EF=3.01)	190	32	222
Base Dishwasher (EF=0.65)	59	10	69
Base Single Speed Pool Pump (RET)	9	0	9
Base Plasma TV	8	1	9
Base LCD TV	43	5	48
Base CRT TV	2	0	2
Base Set-Top Box	52	7	59
Base DVD Player	7	1	8
Base Desktop PC	59	5	63
Base Laptop PC	11	2	13
Base Cooking	342	65	407
Base Miscellaneous	128	22	150
Base House Practices	6,068	683	6,751

Note: We calibrated the whole-house load shape (used for house practices) so that peak demand for base house practices was equal to the sum of the peak demands across end uses by state. Due to modeling limitations (the whole-house load shape inputs are the same for both single family and multifamily); we could not calibrate these values at the building type level.

5.1.3 Non-Residential Baseline

For this potential study, exempt/opt-out customers were split apart from the non-exempt customers. All three groups were broken down into building types, listed below, with non-jurisdictional customers additionally split out from the non-exempt customers:

- Office
- Restaurant (not applicable for exempt/opt-out customers)
- Retail
- Grocery
- Warehouse
- Education
- Health
- Lodging
- Data Center
- Non-Jurisdictional
- Religious Worship
- Other

While we performed baseline analyses for both non-exempt customers and exempt/opt-out customers, this section presents results only for the non-exempt customers, as the exempt/opt-out customers do not contribute to program potential. DNV GL provided Dominion the baseline analysis results for exempt/opt-out customers in a separate technical memorandum.

5.1.3.1 Non-Residential Equipment Saturations

The equipment saturations (percent of non-residential square feet having an end use) were calculated primarily from the results of the commercial saturation surveys. For a few measures, such as linear fluorescent lighting, saturations were broken down into finer levels of detail than was provided by the survey data (for example, 2-lamp 4-foot fixtures versus 4-lamp 4-foot fixtures versus other configurations). In such cases, data from internal DNV GL databases (gleaned from previous potential studies and on-site data collection) were used for the breakouts. The resulting saturations are shown in Table 16.

Table 16. Non-Residential Sector Equipment Saturations

End Use	Office	Restau-rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other
Base Fluorescent Fixture, 4L4'T8	62%	2%	29%	42%	57%	57%	47%	3%	46%	48%	25%	20%
Base Fluorescent Fixture, 2L4'T8, 1 EB	2%	25%	10%	0%	0%	5%	12%	17%	1%	14%	24%	19%
Base Other Fluorescent Fixture	5%	0%	0%	0%	0%	2%	4%	1%	4%	3%	1%	1%
Base High-Efficiency Incandescent Reflector Lamp (100W)	7%	22%	10%	25%	3%	5%	9%	16%	5%	6%	11%	10%
Base High-Efficiency Incandescent A-line Lamp (72W)	4%	11%	5%	12%	1%	2%	4%	8%	2%	3%	5%	5%
Base High-Efficiency Incandescent A-line Lamp (53W)	4%	11%	5%	12%	1%	2%	4%	8%	2%	3%	5%	5%
Base CFL (18W)	8%	14%	17%	1%	6%	10%	9%	19%	17%	11%	9%	11%
Base CFL (23W)	8%	14%	17%	1%	6%	10%	9%	19%	17%	11%	9%	11%
Base HID, 465W	2%	3%	4%	1%	25%	5%	2%	6%	2%	9%	2%	6%
Base CFL Exit Sign	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Base Outdoor High Pressure Sodium 250W Lamp	43%	62%	41%	25%	72%	85%	64%	92%	93%	79%	89%	68%
Base Centrifugal Chiller, 0.58 kW/ton, 500 tons	13%	15%	1%	3%	0%	40%	19%	27%	66%	44%	15%	8%
Base DX Packaged System, EER=10.3, 10 tons	58%	77%	50%	84%	37%	95%	65%	68%	38%	54%	47%	32%
Base Heat Pump (13 SEER, 7.7 HSPF)	40%	24%	18%	7%	20%	75%	41%	53%	5%	23%	39%	30%
Base PTAC, EER=8.3, 1 ton	6%	3%	3%	3%	1%	68%	9%	11%	0%	36%	38%	19%
Base Fan Motor, 5hp, 1800rpm, 87.5%	42%	50%	43%	97%	30%	33%	19%	65%	19%	48%	54%	54%
Base Fan Motor, 15hp, 1800rpm, 91.0%	7%	0%	2%	0%	0%	89%	65%	0%	65%	25%	43%	43%

End Use	Office	Restau-rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other
Base Fan Motor, 40hp, 1800rpm, 93.0%	5%	0%	2%	96%	10%	37%	69%	11%	69%	19%	34%	34%
Base Built-Up Refrigeration System	9%	67%	17%	91%	37%	37%	26%	38%	2%	40%	43%	18%
Base Self-Contained Refrigeration	68%	91%	71%	94%	90%	83%	77%	78%	95%	85%	96%	62%
Base Desktop PC	98%	64%	80%	85%	98%	100%	95%	97%	98%	98%	95%	90%
Base Laptop PC	87%	44%	61%	66%	86%	98%	68%	87%	90%	83%	72%	71%
Base Monitor, CRT	60%	47%	42%	28%	68%	94%	64%	84%	79%	60%	45%	51%
Base Monitor, LCD	79%	42%	48%	92%	75%	93%	78%	87%	95%	96%	89%	78%
Base Copier	97%	45%	87%	29%	89%	99%	99%	94%	95%	97%	98%	86%
Base Multifunction	97%	78%	81%	84%	94%	98%	84%	93%	90%	97%	91%	86%
Base Printer	95%	30%	51%	17%	83%	99%	82%	43%	69%	92%	53%	71%
Base Data Center/Server Room	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%
Base Water Heating	89%	39%	63%	78%	83%	72%	55%	31%	89%	39%	71%	51%
Base Refrigerated Vending Machines	99%	100%	90%	98%	99%	100%	99%	96%	100%	98%	100%	97%
Base Non-Refrigerated Vending Machines	78%	88%	54%	11%	95%	71%	74%	32%	100%	68%	3%	47%
Base Convection Oven	2%	15%	3%	56%	15%	8%	5%	20%	0%	22%	49%	5%
Base Fryer	1%	19%	1%	49%	11%	11%	3%	19%	0%	13%	1%	4%
Base Steamer	1%	15%	1%	42%	11%	1%	5%	7%	0%	16%	3%	2%
Base Heating, Heat Pump (13 SEER 7.7HSPF)	35%	8%	8%	3%	2%	17%	23%	25%	0%	6%	6%	22%
Base Heating, Other Electric	35%	21%	28%	76%	12%	0%	32%	20%	41%	14%	46%	21%
Base Miscellaneous	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

5.1.3.2 Non-Residential End-Use Energy Intensities

Table 17 shows the end-use energy intensities (EUIs) for the non-Residential sector by base measure. End-use energy intensities represent the energy use per square feet for businesses that have that end-use (for example, chiller annual kWh for non-Residential square feet with chillers). EUIs were developed from a variety of sources. At the base measure level, lighting EUIs were developed from engineering calculations based on wattage and hours of use. For products covered by the ENERGY STAR program, the EPA's calculators were used.

At the end-use level, EUIs were obtained for the South Atlantic Census Division from the DOE's 2003[18] Commercial Building Energy Consumption Survey (CBECS). This provided concrete, survey-based, regionally appropriate values to use to calibrate the base measure-level EUIs. The resulting EUIs, when combined with the saturation data, produced intensities at the building type level that are consistent with values estimated from the Dominion survey data.

[18] The most recent for which data is available.

Table 17. Non-Residential End-Use Energy Intensities (kWh per End-Use Square Foot)

	Office	Restau-rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other
Base Fluorescent Fixture, 4L4'T8	4.8	7.8	5.2	7.4	2.1	3.4	3.1	1.6	6.1	4.9	1.6	4.9
Base Fluorescent Fixture, 2L4'T8, 1 EB	2.7	3.6	2.9	5.6	2.0	2.2	1.4	1.1	3.5	3.3	1.2	3.7
Base Other Fluorescent Fixture	2.2	0.0	1.5	0.0	3.1	0.4	1.1	0.5	2.8	1.3	0.3	1.0
Base High-Efficiency Incandescent Reflector Lamp (100W)	18.7	4.9	7.9	4.7	0.0	0.2	1.3	2.5	24.2	9.4	1.9	7.6
Base High-Efficiency Incandescent A-line Lamp (72W)	13.4	3.5	5.7	3.4	3.5	0.1	0.9	1.8	17.4	6.8	1.4	5.5
Base High-Efficiency Incandescent A-line Lamp (53W)	9.9	2.6	4.2	2.5	2.6	0.1	0.7	1.3	12.8	5.0	1.0	4.0
Base CFL (18W)	0.8	0.9	0.9	4.2	0.9	1.3	0.3	0.3	1.0	1.3	0.2	1.0
Base CFL (23W)	1.0	1.1	1.2	5.4	1.1	1.7	0.4	0.4	1.3	1.6	0.3	1.3
Base HID, 465W	0.0	0.1	0.0	14.5	2.8	5.1	0.0	2.6	0.0	3.7	0.9	2.9
Base CFL Exit Sign	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Outdoor High Pressure Sodium 250W Lamp	0.5	1.6	0.7	0.2	0.4	0.5	0.2	0.2	0.7	0.5	0.1	0.3
Base Centrifugal Chiller, 0.58 kW/ton, 500 tons	3.6	5.8	2.7	2.7	1.6	1.5	3.0	2.8	10.8	2.3	1.0	2.1
Base DX Packaged System, EER=10.3, 10 tons	3.6	5.8	2.7	2.7	1.6	1.5	3.0	2.8	10.8	2.3	1.0	2.1
Base Heat Pump (13 SEER, 7.7 HSPF)	3.6	5.8	2.7	2.7	1.6	1.5	3.0	2.8	10.8	2.3	1.0	2.1
Base PTAC, EER=8.3, 1 ton	3.6	5.8	2.7	2.7	1.6	1.5	3.0	2.8	10.8	2.3	1.0	2.1
Base Fan Motor, 5hp, 1800rpm, 87.5%	2.6	3.0	2.1	2.3	1.1	1.0	3.0	1.9	5.5	1.6	0.7	1.4
Base Fan Motor, 15hp, 1800rpm, 91.0%	2.6	3.0	2.1	2.3	1.1	1.0	3.0	1.9	5.5	1.6	0.7	1.4
Base Fan Motor, 40hp, 1800rpm, 93.0%	2.6	3.0	2.1	2.3	1.1	1.0	3.0	1.9	5.5	1.6	0.7	1.4

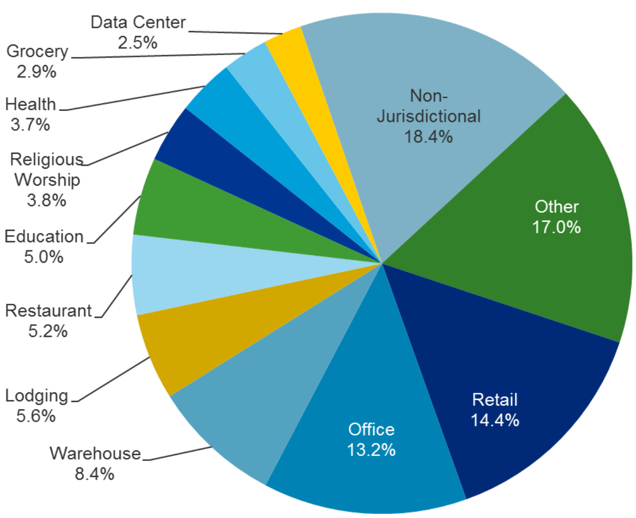
	Office	Restau-rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other
Base Built-Up Refrigeration System	0.0	0.0	0.0	10.2	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Self-Contained Refrigeration	0.5	7.0	1.0	1.1	0.2	0.5	0.5	0.9	0.5	0.7	0.5	1.1
Base Desktop PC	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1
Base Laptop PC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Monitor, CRT	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Base Monitor, LCD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Copier	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Multifunction	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Printer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Data Center/Server Room	150.1	105.0	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	82.5	120.1
Base Water Heating	0.3	1.6	0.2	0.3	0.1	0.2	0.3	1.0	0.1	0.3	0.2	0.4
Base Refrigerated Vending Machines	0.1	0.0	0.0	0.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
Base Non-Refrigerated Vending Machines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Convection Oven	0.9	1.9	0.6	0.4	0.1	0.6	1.9	0.1	0.0	0.5	0.3	0.3
Base Fryer	0.7	1.9	0.3	0.6	0.2	0.1	3.2	0.2	0.0	0.4	0.5	0.5
Base Steamer	2.5	2.9	1.3	1.0	0.1	0.2	1.6	0.1	0.0	0.8	0.2	0.2
Base Heating, Heat Pump (13 SEER 7.7HSPF)	0.6	0.2	0.3	0.3	0.4	0.2	0.7	0.5	0.2	0.4	0.2	0.4
Base Heating, Other Electric	0.6	0.2	0.3	0.3	0.4	0.2	0.7	0.5	0.2	0.4	0.2	0.4
Base Miscellaneous	2.2	2.6	2.2	2.4	0.9	0.6	3.3	1.4	0.6	1.5	1.7	1.7

5.1.3.3 Non-Residential Building Stock and Energy Use

2013 CBECS data from the South Atlantic Census Division was used to estimate the proportion of customers and the average floor space by building type. Energy use was then calculated as the product of the non-Residential floor space, equipment saturation, and the end-use energy intensity. Table 18 shows floor space and the breakout of energy use by building type. Non-jurisdictional customers represent the largest share of energy use followed by 'other' buildings.[19] Data centers represent the largest share of energy use among opt-out/exempt customers, followed by offices.

Figure 13 and Figure 14show the breakout of energy use by building type and by end-use, respectively. Indoor lighting, cooling, miscellaneous, and ventilation end uses represent the largest shares of energy use.

Figure 13. Non-Residential Energy Use by Building Type



[19] Other buildings include, public safety, services, community centers, recreation, entertainment, etc.

Figure 14. Non-Residential Energy Use by End-Use

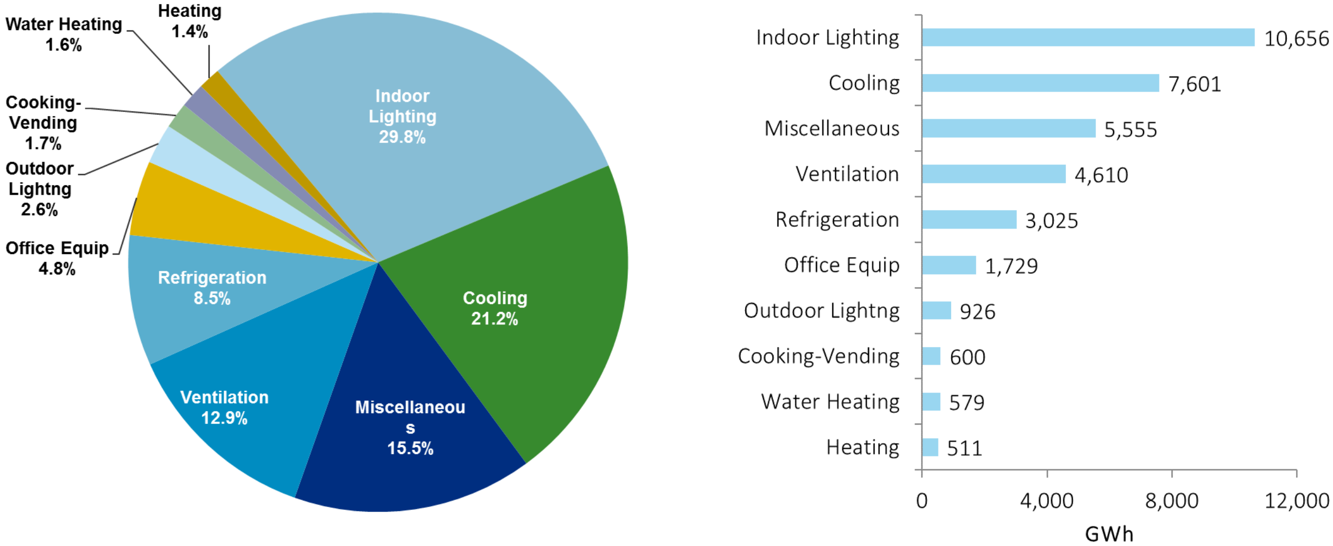


Table 18 on the next page shows non-residential floor space by building type and resulting energy use by building type and equipment type.

Table 18. Non-Residential Sector Floor space (1,000 sf) and Energy Use (MWh) by End-Use and Building Type

	Office	Restau -rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other	Total
Floor Space (1000 sf)	322,343	82,323	526,547	39,383	506,895	176,407	86,772	202,864	6,069	531,319	221,837	602,306	3,305,065
MWh by End Use													
Base Fluorescent Fixture, 4L4'T8	959,933	13,206	808,861	124,100	612,116	347,955	128,630	9,910	17,012	1,254,935	88,072	595,338	4,960,067
Base Fluorescent Fixture, 2L4'T8, 1 EB	15,567	74,688	154,475	394	4,032	20,947	14,589	38,944	280	240,657	63,027	426,038	1,053,637
Base Other Fluorescent Fixture	33,783	0	1,207	0	612	1,620	3,919	756	607	22,925	861	5,817	72,107
Base High-Efficiency Incandescent Reflector Lamp (100W)	435,703	85,970	406,213	45,934	0	1,693	9,707	81,791	7,198	293,019	45,127	478,374	1,890,727
Base High-Efficiency Incandescent A-line Lamp (72W)	156,853	30,949	146,237	16,536	25,264	609	3,494	29,445	2,591	105,487	16,246	172,215	705,926
Base High-Efficiency Incandescent A-line Lamp (53W)	115,461	22,782	107,647	12,172	18,597	449	2,572	21,675	1,907	77,650	11,959	126,769	519,640
Base CFL (18W)	19,930	10,277	83,258	2,305	24,573	23,651	2,280	11,929	1,019	73,107	4,712	63,281	320,320
Base CFL (23W)	25,466	13,132	106,385	2,945	31,399	30,221	2,913	15,243	1,301	93,415	6,020	80,859	409,298
Base HID, 465W	0	275	0	5,508	355,025	46,681	0	30,542	0	172,831	3,996	109,463	724,321
Base CFL Exit Sign	10,650	3,450	9,542	216	2,095	2,522	3,588	6,847	260	13,511	2,302	12,061	67,043
Base Outdoor High Pressure Sodium 250W Lamp	72,874	84,236	152,866	1,678	131,955	76,243	9,572	44,434	3,826	205,233	28,698	114,349	925,963
Base Centrifugal Chiller, 0.58 kW/ton, 500 tons	146,304	69,432	20,349	2,911	0	105,988	50,723	153,512	42,976	528,645	34,221	104,057	1,259,119
Base DX Packaged System, EER=10.3, 10 tons	663,841	367,939	717,031	90,349	298,145	254,210	169,753	392,113	24,509	651,321	110,233	401,077	4,140,521
Base Heat Pump (13 SEER, 7.7 HSPF)	453,221	115,321	266,299	8,064	161,415	200,014	108,151	303,849	3,139	282,989	89,702	380,915	2,373,079
Base PTAC, EER=8.3, 1 ton	72,622	13,914	46,968	3,741	7,649	182,163	24,204	63,800	0	438,441	89,037	239,977	1,182,517
Base Fan Motor, 5hp, 1800rpm, 87.5%	359,262	123,136	485,853	87,850	168,085	59,953	48,660	256,558	6,290	402,757	82,950	450,435	2,531,789
Base Fan Motor, 15hp, 1800rpm, 91.0%	62,245	0	16,931	0	0	160,485	169,134	0	21,864	209,952	66,125	359,070	1,065,807

	Office	Restau -rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other	Total
Base Fan Motor, 40hp, 1800rpm, 93.0%	39,241	0	16,931	86,859	55,750	66,896	179,714	44,354	23,232	161,572	52,473	284,936	1,011,959
Base Built-Up Refrigeration System	0	0	0	365,518	402,256	0	0	0	0	0	0	0	767,774
Base Self-Contained Refrigeration	105,401	522,271	391,191	41,652	107,502	75,382	33,289	144,810	2,802	327,619	112,058	393,426	2,257,403
Base Desktop PC	43,094	4,658	18,055	1,658	25,127	11,828	7,548	9,301	459	62,303	10,850	34,029	228,912
Base Laptop PC	3,921	191	746	51	1,783	1,320	391	447	33	5,511	746	1,944	17,083
Base Monitor, CRT	9,140	2,490	4,114	314	5,181	4,798	2,080	4,380	249	13,409	1,902	7,858	55,916
Base Monitor, LCD	8,178	1,040	2,571	494	4,138	2,478	1,335	1,940	120	14,397	2,259	7,138	46,088
Base Copier	14,969	1,939	8,913	398	6,382	3,159	2,104	2,705	102	17,364	4,401	12,602	75,040
Base Multifunction	2,542	738	1,364	159	1,433	390	339	417	13	2,491	575	1,875	12,337
Base Printer	14,825	842	3,901	133	6,405	3,301	1,708	1,179	40	20,463	1,776	9,812	64,384
Base Data Center/Server Room	96,883	5,982	10,880	323	63,424	65,570	27,186	38,010	728,565	121,538	7,871	63,398	1,229,630
Base Water Heating	88,842	50,579	74,603	9,452	28,443	27,040	12,203	63,823	366	63,644	30,734	118,529	568,259
Base Refrigerated Vending Machines	20,092	3,356	18,478	8,250	19,504	6,898	4,653	15,245	237	22,985	5,079	21,478	146,255
Base Non-Refrigerated Vending Machines	521	51	90	15	814	107	91	87	10	410	2	224	2,423
Base Convection Oven	4,761	23,317	11,839	9,351	6,484	7,589	7,392	3,039	0	62,437	30,705	7,625	174,539
Base Fryer	3,012	29,328	2,164	12,162	13,463	1,346	7,126	7,648	0	28,205	1,587	13,707	119,749
Base Steamer	7,763	37,020	8,435	16,871	5,619	366	6,354	1,254	0	68,155	1,394	3,370	156,603
Base Heating, Heat Pump (13 SEER 7.7HSPF)	65,849	1,509	11,742	409	2,811	4,886	13,652	25,374	0	12,522	2,722	58,146	199,621
Base Heating, Other Electric	66,519	4,170	42,895	9,974	22,150	0	19,213	20,349	402	28,041	22,217	54,003	289,933
Base Miscellaneous	709,155	214,039	1,158,404	94,519	456,205	105,844	286,347	284,010	3,641	774,466	377,123	1,023,920	5,487,675
Total	4,908,423	1,932,228	5,317,436	1,063,263	3,075,838	1,904,601	1,364,615	2,129,721	895,054	6,874,408	1,409,762	6,238,118	37,113,466

5.1.3.4 Non-Residential Peak Demand

Similar to the residential sector, Dominion's annual hourly 8,760 load data was combined with non-residential end-use load shapes from DNV GL's end-use databases to allocate annual energy usage to time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, was calibrated to equal the Dominion summer peak. Non-residential peak demand estimates by segment and end use are summarized in Table 19.

Table 19. Non-Residential Peak Demand (MW) by End-Use and Building Type

	Office	Restau -rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other	Total
Base Fluorescent Fixture, 4L4'T8	162.4	2.4	133.1	17.2	98.9	42.7	17.8	1.3	2.7	202.9	13.6	91.9	786.9
Base Fluorescent Fixture, 2L4'T8, 1 EB	2.6	13.4	25.4	0.1	0.7	2.6	2.0	5.0	0.0	38.9	9.7	65.7	166.2
Base Other Fluorescent Fixture	5.7	0.0	0.2	0.0	0.1	0.2	0.5	0.1	0.1	3.7	0.1	0.9	11.7
Base High-Efficiency Incandescent Reflector Lamp (100W)	73.7	15.4	66.8	6.4	0.0	0.2	1.3	10.5	1.1	47.4	7.0	73.8	303.7
Base High-Efficiency Incandescent A-line Lamp (72W)	26.5	5.6	24.1	2.3	4.1	0.1	0.5	3.8	0.4	17.1	2.5	26.6	113.4
Base High-Efficiency Incandescent A-line Lamp (53W)	19.5	4.1	17.7	1.7	3.0	0.1	0.4	2.8	0.3	12.6	1.8	19.6	83.5
Base CFL (18W)	3.4	1.8	13.7	0.3	4.0	2.9	0.3	1.5	0.2	11.8	0.7	9.8	50.4
Base CFL (23W)	4.3	2.4	17.5	0.4	5.1	3.7	0.4	2.0	0.2	15.1	0.9	12.5	64.4
Base HID, 465W	0.0	0.0	0.0	0.8	57.4	5.7	0.0	3.9	0.0	27.9	0.6	16.9	113.3
Base CFL Exit Sign	1.4	0.6	1.6	0.0	0.4	0.2	0.5	1.0	0.0	1.9	0.3	1.8	9.8
Base Outdoor High Pressure Sodium 250W Lamp	0.9	5.1	9.1	0.0	1.6	2.8	0.1	0.3	0.0	7.8	2.0	8.0	37.8
Base Centrifugal Chiller, 0.58 kW/ton, 500 tons	93.1	39.5	15.3	1.7	0.0	49.5	25.3	84.0	9.6	354.2	24.1	73.2	769.5
Base DX Packaged System, EER=10.3, 10 tons	422.2	209.4	538.7	53.6	257.8	118.7	84.8	214.6	5.5	436.4	77.5	282.0	2,701.3
Base Heat Pump (13 SEER, 7.7 HSPF)	288.3	65.6	200.1	4.8	139.6	93.4	54.0	166.3	0.7	189.6	63.1	267.8	1,533.2
Base PTAC, EER=8.3, 1 ton	46.2	7.9	35.3	2.2	6.6	85.0	12.1	34.9	0.0	293.8	62.6	168.7	755.4
Base Fan Motor, 5hp, 1800rpm, 87.5%	98.6	28.9	123.7	17.1	47.2	10.6	9.0	49.3	1.4	107.3	21.4	116.3	631.0
Base Fan Motor, 15hp, 1800rpm, 91.0%	17.1	0.0	4.3	0.0	0.0	28.5	31.2	0.0	4.9	55.9	17.1	92.7	251.7
Base Fan Motor, 40hp, 1800rpm, 93.0%	10.8	0.0	4.3	16.9	15.7	11.9	33.2	8.5	5.2	43.1	13.6	73.6	236.6
Base Built-Up Refrigeration System	0.0	0.0	0.0	53.5	69.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.8
Base Self-Contained Refrigeration	13.4	71.1	54.1	6.1	18.5	9.5	4.4	19.2	0.5	43.3	15.3	53.8	309.3
Base Desktop PC	5.4	0.8	2.9	0.3	3.8	0.9	1.0	1.3	0.1	8.2	1.5	4.7	30.9

	Office	Restau-rant	Retail	Grocery	Ware-house	Education	Health	Lodging	Data Center	Non-Juris-dictional	Religious Worship	Other	Total
Base Laptop PC	0.5	0.0	0.1	0.0	0.3	0.1	0.1	0.1	0.0	0.7	0.1	0.3	2.2
Base Monitor, CRT	1.2	0.4	0.7	0.1	0.8	0.4	0.3	0.6	0.0	1.8	0.3	1.1	7.5
Base Monitor, LCD	1.0	0.2	0.4	0.1	0.6	0.2	0.2	0.3	0.0	1.9	0.3	1.0	6.2
Base Copier	1.9	0.3	1.4	0.1	1.0	0.2	0.3	0.4	0.0	2.3	0.6	1.7	10.2
Base Multifunction	0.3	0.1	0.2	0.0	0.2	0.0	0.0	0.1	0.0	0.3	0.1	0.3	1.7
Base Printer	1.9	0.1	0.6	0.0	1.0	0.3	0.2	0.2	0.0	2.7	0.2	1.4	8.6
Base Data Center/Server Room	12.2	1.1	1.8	0.1	9.6	5.1	3.5	5.1	115.2	16.0	1.1	8.7	179.6
Base Water Heating	10.9	7.8	10.9	1.4	4.1	1.9	1.4	7.8	0.1	8.2	4.1	15.9	74.4
Base Refrigerated Vending Machines	2.7	0.6	3.0	1.2	3.3	0.5	0.6	2.3	0.0	3.3	0.8	3.2	21.5
Base Non-Refrigerated Vending Machines	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.4
Base Convection Oven	0.6	4.3	1.9	1.2	1.0	0.5	1.3	0.6	0.0	9.0	4.5	1.1	26.1
Base Fryer	0.4	5.5	0.4	1.5	2.0	0.1	1.2	1.4	0.0	4.1	0.2	2.0	18.8
Base Steamer	1.1	6.9	1.4	2.1	0.8	0.0	1.1	0.2	0.0	9.8	0.2	0.5	24.2
Base Heating, Heat Pump (13 SEER 7.7HSPF)	4.4	0.0	0.1	0.0	0.0	0.1	0.7	0.7	0.0	0.5	0.1	1.3	7.9
Base Heating, Other Electric	4.5	0.0	0.3	0.0	0.0	0.0	1.0	0.5	0.0	1.2	0.5	1.3	9.3
Base Miscellaneous	93.8	38.2	188.3	13.7	78.2	8.4	36.2	42.0	0.6	109.7	57.0	154.8	820.9
Total	1,433	540	1,499	207	836	487	327	673	149	2,091	406	1,655	10,302

5.1.3.5 Non-Residential Comparisons to CBECS

The table below compares the results of the non-residential baseline analysis to EIA's Commercial Buildings Energy Consumption Survey (CBECS).

The most recent CBECS for which data is available was conducted in 2012 (for the 2013 baseline study we compared our results to the 2003 CBECS). The geographical resolution is not as great for CBECS as for RECS. We therefore compare the Dominion baseline results as a whole to the South Atlantic Census division (the finest granularity available), which includes Delaware, Maryland, West Virginia, Virginia, North Carolina, South Carolina, Georgia, and Florida.

Figure 15 and Figure 16, below, compare the distribution of energy use by building type and end use, respectively. The breakouts from the baseline analysis are broadly similar to CBECS.

Figure 15. Comparison of Non-Residential Baseline Energy Use by Building Type to CBECS

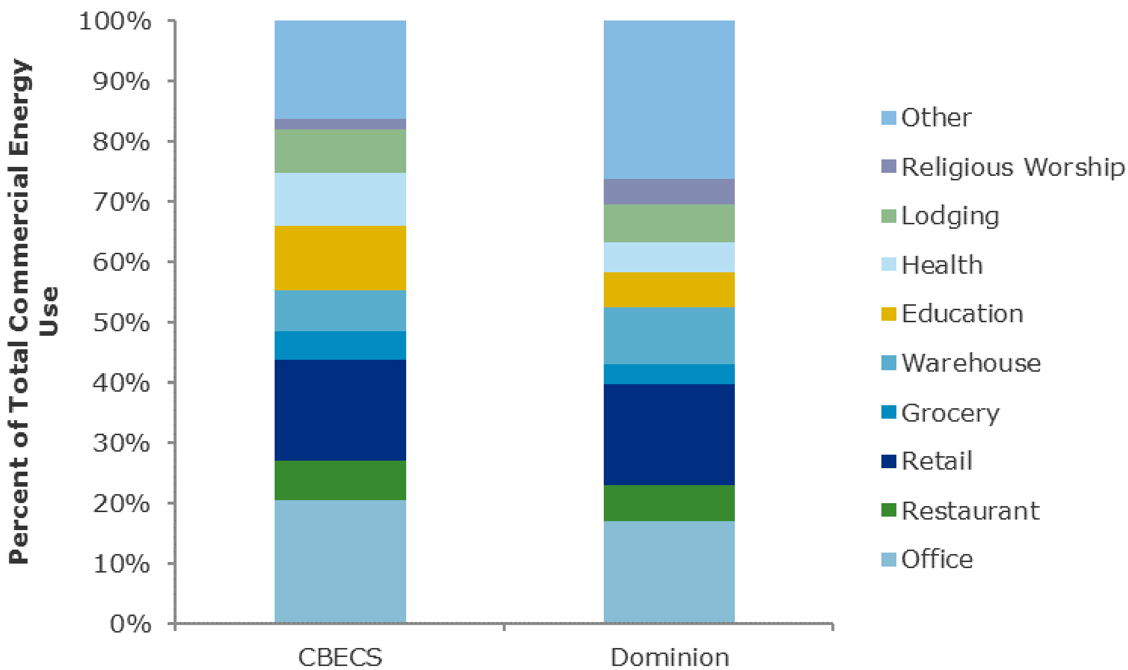
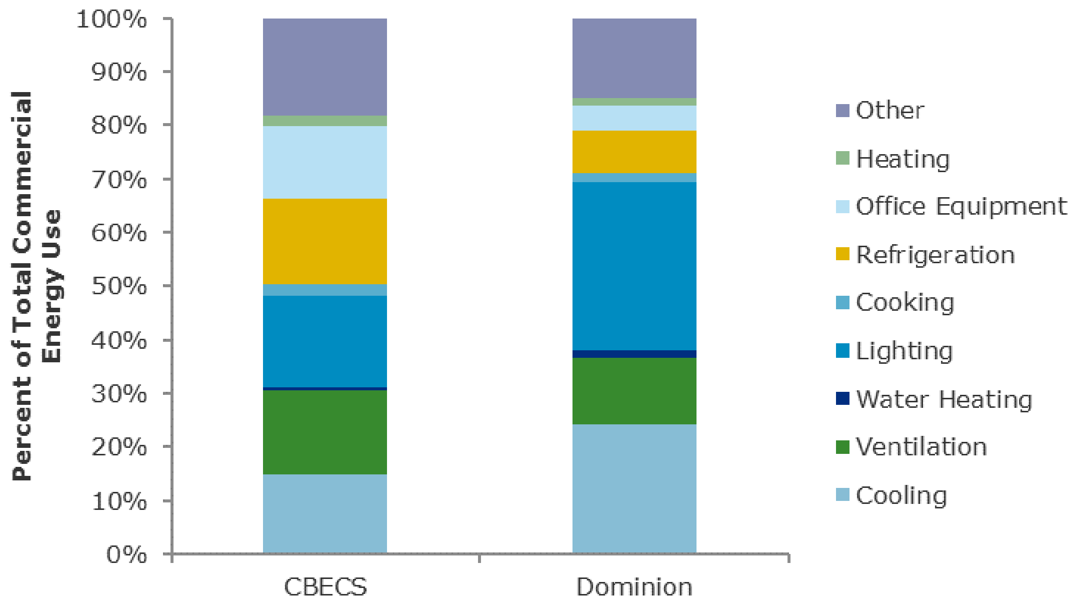


Figure 16. Comparison of Non-Residential Baseline Energy Use by End-Use to CBECS

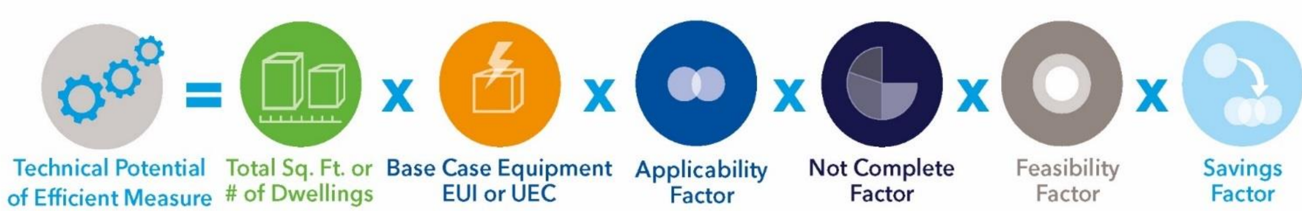


5.2 Technical and Economic Potential Results

This section contains a summary of findings from the analysis of technical and economic savings potential of electric energy efficiency efforts in Dominion's service territory. Technical potential is defined as the complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective. Economic potential is defined as the technical potential of those energy conservation measures that are cost-effective when compared to supply-side alternatives. All measures with a total resource cost (TRC) greater than one are considered to have economic potential.

In our bottom-up modeling approach, we first estimate technical potential for energy savings by integrating key measure and market segment parameters using Equation 1:

Equation 1. Technical Potential of an Efficient Measure



Where:

- **Square Feet** is the total floor space for all buildings in the market segment. For the residential analysis, the number of dwelling units is substituted for square feet.

- **Base Case Equipment Energy Use Intensity** (EUI) is the energy used per square foot by each base case technology in each market segment. This is the consumption of the energy-using equipment that the efficient technology replaces or affects. For example, if the efficient measure were a CFL, the base EUI would be the annual kWh per square foot of an equivalent incandescent lamp. For the residential analysis, unit energy consumption (UECs), energy used per dwelling, are substituted for EUIs and were developed as part of the Conditional Demand Analysis.
- **Applicability Factor** is the fraction of the floor space (or dwelling units) that is applicable for the efficient technology in a given market segment; for the example above, the percentage of floor space lit by incandescent bulbs. This input was developed through results of the 2013 residential and commercial saturation surveys and the Conditional Demand Analysis and Baseline Analysis.
- **Not Complete Factor** is the fraction of applicable floor space (or dwelling units) that has not yet been converted to the efficient measure; that is, one minus the fraction of floor space that already has the EE measure installed. DNV GL relied on the results of Dominion's saturation surveys to estimate this value when possible and utilized other recent saturation surveys and internal databases for other measures not included in the saturation surveys.
- **Feasibility Factor** is the fraction of the applicable floor space (or dwelling units) that is technically feasible for conversion to the efficient technology from an engineering perspective. DNV GL engineers familiar with Dominion's service territory reviewed these values to ensure they were consistent with Dominion's building stock.
- **Savings Factor** is the reduction in energy consumption resulting from application of the efficient technology. DNV GL estimated energy savings through the use of sources including the STEP manual, LBNL Home Energy Savers Model, and other engineering calculations.

Technical potential for peak demand reduction is calculated analogously.

Economic potential is then assessed by first developing a supply-curve analysis. This analysis eliminates double counting of measure savings. On a market segment and end-use/technology basis, measures are stacked in order of cost-effectiveness, and the energy consumption of the system being affected by the efficiency measures reduces as each measure is applied. As a result, the savings attributable to each subsequent measure decrease if the measures are interactive. After eliminating double counting of savings, the benefits and costs associated with a given measure and market segment are compared using the Total Resource Cost (TRC) test or other cost relevant cost effectiveness test. Measures with a TRC ratio greater than 1.0 will be passed on to our achievable potential analysis.

5.2.1 Electric Energy Efficiency Potential Results

In this section, we present the technical and economic potential results for all electric measures considered in the study. Economic potential shown in the majority of this report is for the base avoided cost scenario. We briefly present a comparison of the economic potential under the High and Low scenarios in Section 0.

5.2.2 Overall Technical and Economic Potential

Figure 17 presents our overall estimates of total technical and economic potential for electrical energy and peak demand savings for Dominion.

Figure 17. Estimated Electric Technical and Economic Potential, 2027

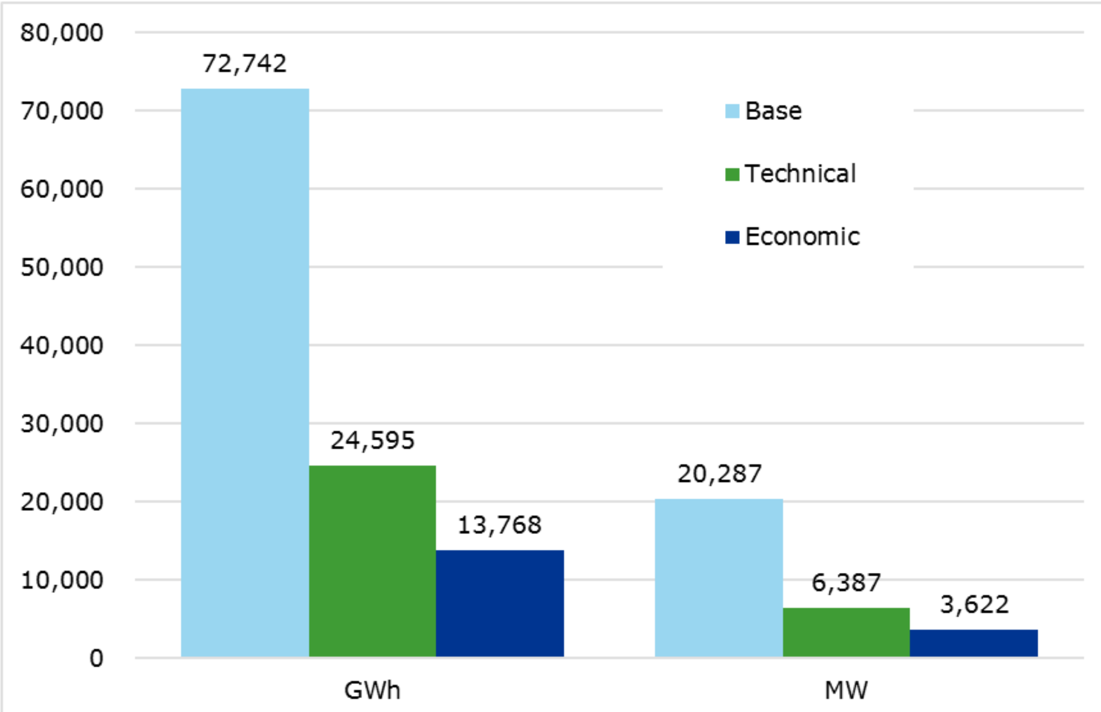


Table 20 shows technical and economic potential for energy and demand, respectively. The values of both energy savings and peak-demand reductions are incorporated into the measure TRC test.

Technical potential energy savings is estimated at 24,595 GWH per year, and economic potential at 13,768 GWH per year by 2027 (about 34% and 19% of base 2027 usage, respectively). Technical potential peak demand savings is estimated at 6,378 MW and economic potential at 3,622 MW by 2027 (about 31% and 18% of base 2027 demand, respectively).

Table 20. Estimated Electric Technical and Economic Potential, 2027

	2027 Base Usage (GWh)	Technical GWh	Economic GWh	2027 Base Demand (MW)	Technical MW	Economic MW
Total	72,742	24,595	13,768	20,287	6,387	3,622
% of Base		34%	19%		31%	18%

5.2.3 Base-Case Technical and Economic Potential Detail

In this section, we describe technical and economic potential in more detail for the base avoided cost case, and further describe potentials by sector, state, building type, and by end use.

5.2.4 Potentials by Sector

Figure 18 and Figure 19 show the breakdown of technical and economic potential by sector, as compared to the total base consumption and demand in 2027. The residential sector is 57% of technical energy savings, and 47% of economic energy savings. The residential sector is 62% of technical demand potential, and 49% of the corresponding economic potential.

Figure 18. Technical and Economic Energy Savings by Sector (GWH)

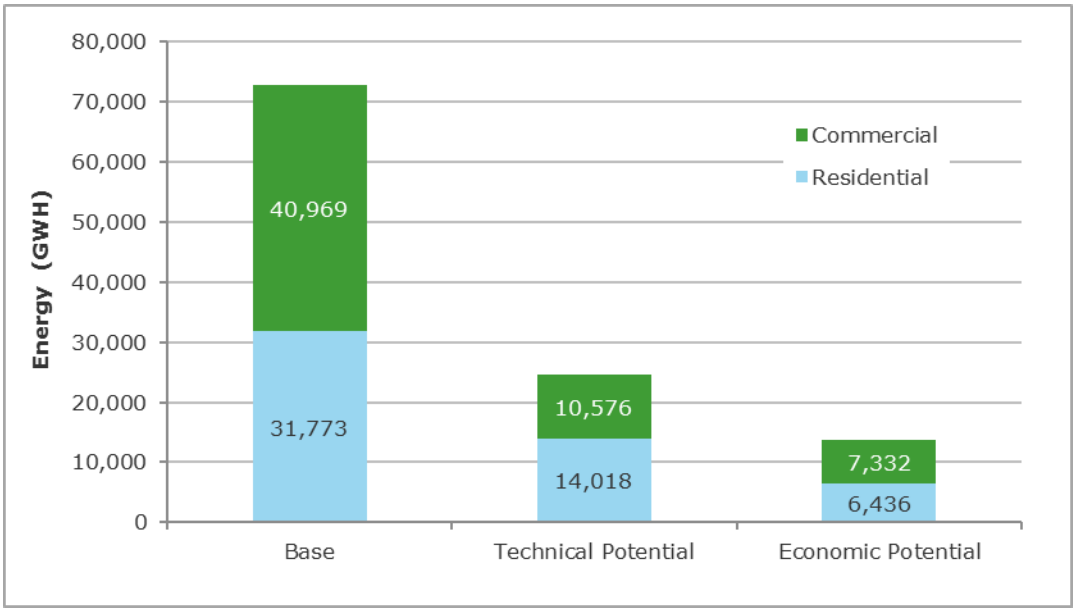
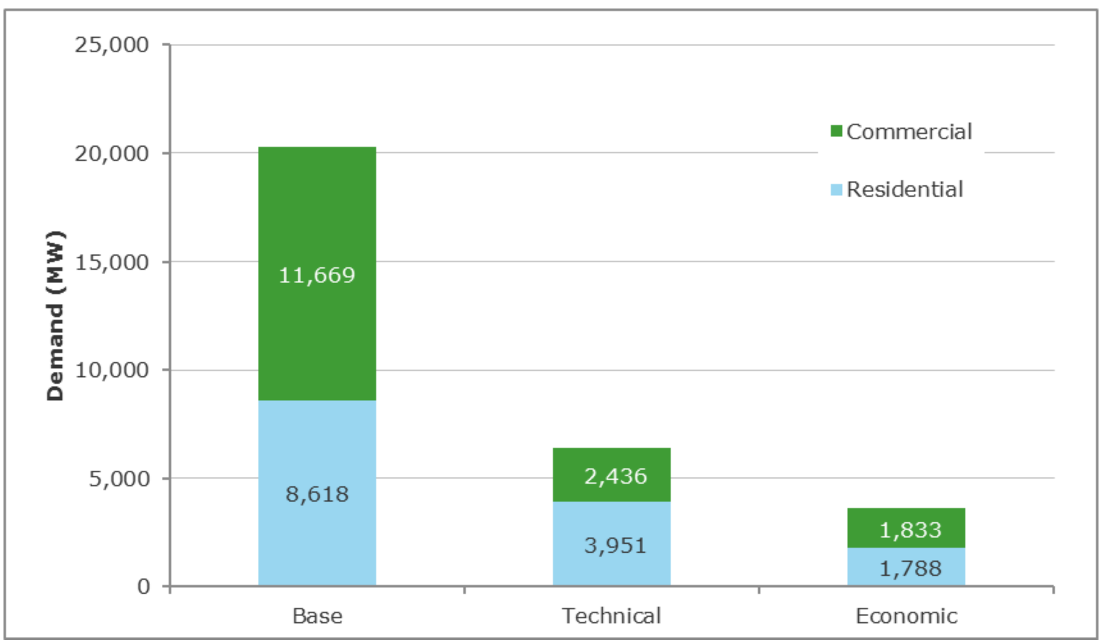


Figure 19. Technical and Economic Peak Demand Savings by Sector (MW)



Finally, Table 21 and Table 22 show the contribution of technical and economic potential from each sector in the current study (2027 Base), as well as the 2014 study (2023 Base). These tables also compare the potential savings of each sector to base consumption and demand. The residential sector has higher technical and economic energy savings potential in relation to base energy use than does the commercial sector. In technical and economic peak demand savings, residential is also higher than commercial as a percent of base demand, but the commercial sector does have a larger amount of total MW economic potential.

Table 21. Technical and Economic Potential Energy Savings by Sector

Sector	2027 Base Energy Use (GWH)	Ten Year Cumulative Potential - GWh		2023 Base Energy Use (GWH)	Ten Year Cumulative Potential - GWh	
		Technical Potential (Current)	Economic Potential (Current)		Technical Potential (2014)	Economic Potential (2014)
Residential						
Existing	28,843	13,373	5,790	28,285	14,720	6,593
New	2,930	646	646	2,970	655	655
Subtotal	31,773	14,018	6,436	31,255	15,374	7,247
% of Base		**44%**	**20%**		**49%**	**23%**
Non-residential						
Existing	35,824	9,306	6,301	28,474	8,630	5,777
New	5,144	1,271	1,031	4,697	1,176	821
Subtotal	40,969	10,576	7,332	33,170	9,806	6,598
% of Base		**26%**	**18%**		**30%**	**20%**
Total	72,742	24,595	13,768	74,805	15,374	16,033
% of Base		**34%**	**19%**		**49%**	**22%**

Table 22. Technical and Economic Potential Demand Savings by Sector

Sector	2027 Base Demand (MW)	Ten Year Cumulative Potential - MW		2023 Base Demand (MW)	Ten Year Cumulative Potential - MW	
		Technical Potential (Current)	Economic Potential (Current)		Technical Potential (2014)	Economic Potential (2014)
Residential						
Existing	7,892	3,893	1,730	7,073	3,829	1,609
New	726	58	58	735	59	59
Subtotal	8,618	3,951	1,788	7,809	3,888	1,688
% of Base		**46%**	**21%**		**50%**	**21%**
Non-residential						
Existing	10,601	2,172	1,614	8,535	2,274	1,580
New	1,068	264	219	968	311	225
Subtotal	11,669	2,436	1,833	9,503	2,584	1,805
% of Base		**21%**	**16%**		**27%**	**19%**
Total	20,287	6,387	3,622	20,640	7,282	4,026
% of Base		**31%**	**18%**		**35%**	**20%**

5.2.5 Potentials by Building Type

This section presents technical and economic potential by residential and commercial building type to provide more detail about where potential savings exist in Dominion's service territory.

5.2.5.1 Residential

Figure 20 and Figure 21 show the potentials in the residential sector by building type. Single family homes account for 93% of the economic energy potential and 92% of the economic demand potential.

Figure 20. Energy Savings Potential (GWh) by Residential Building Type

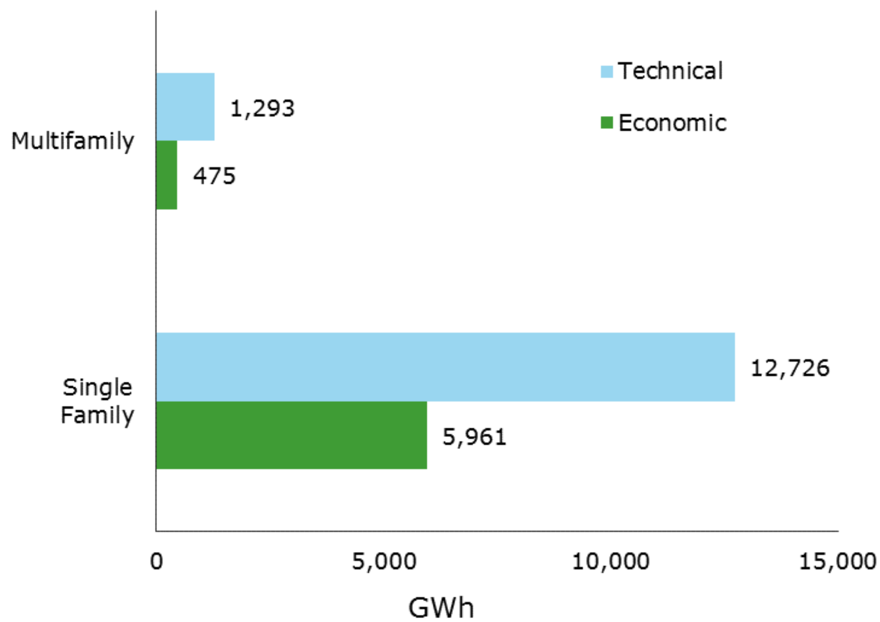


Figure 21. Demand Savings Potential (MW) by Residential Building Type

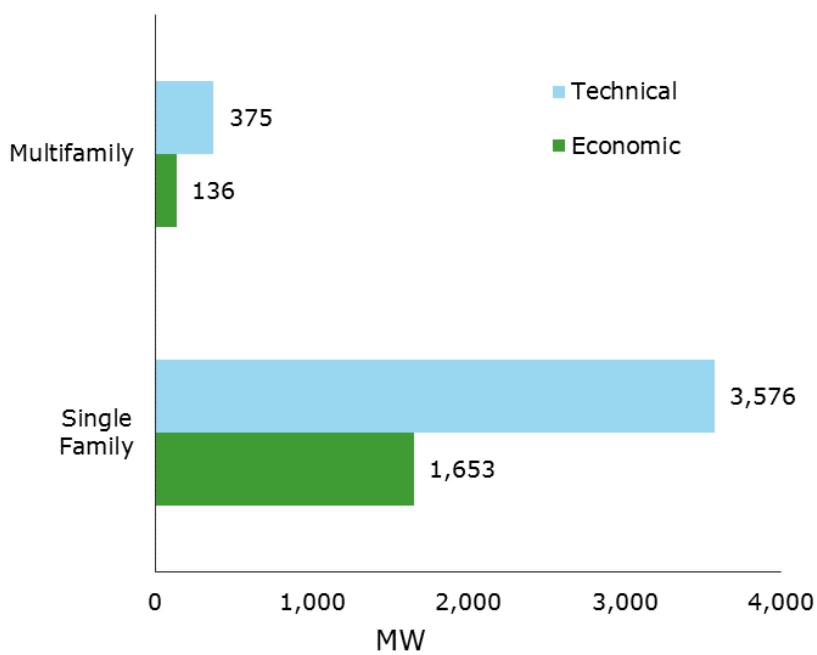


Table 23 shows the contribution from each building type toward the various types of potential.

Table 23. Energy and Demand Savings Potential by Residential Building Type

Residential Building Type	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Single Family	12,726	5,961	3,576	1,653
Multifamily	1,293	475	375	136
Total	**14,018**	**6,436**	**3,951**	**1,788**

5.2.5.2 Non-Residential

Figure 22 and Figure 23 show the building type breakdown of non-residential potential. Non-jurisdictional buildings account for 20% of the economic energy and 19% of the demand potential, followed by miscellaneous, office, and retail.

Figure 22. Energy Savings Potential by Non-Residential Building Type

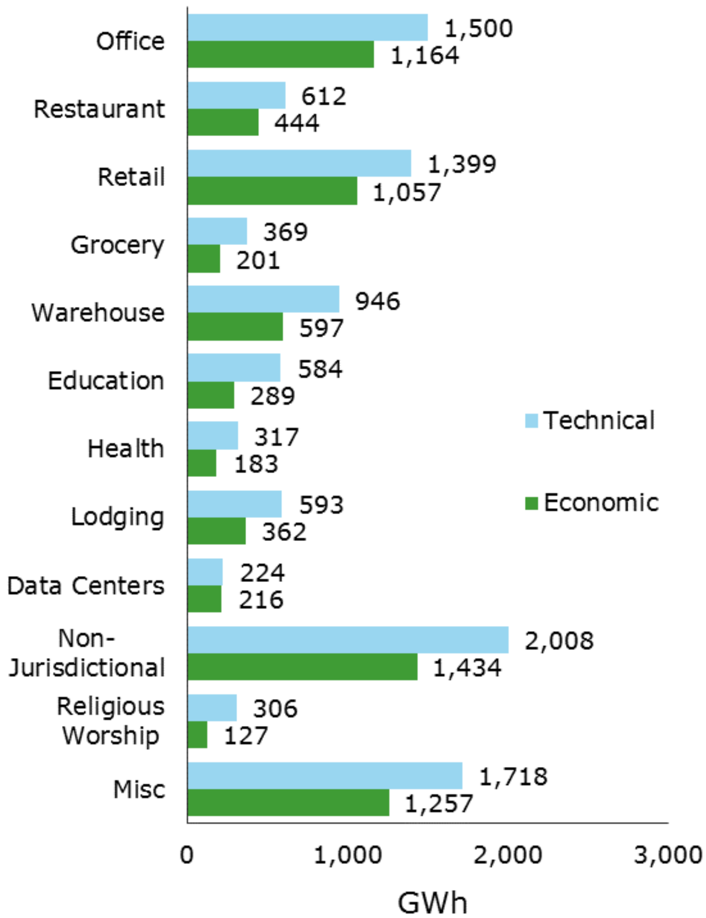


Figure 23. Demand Savings Potential by Non-Residential Building Type

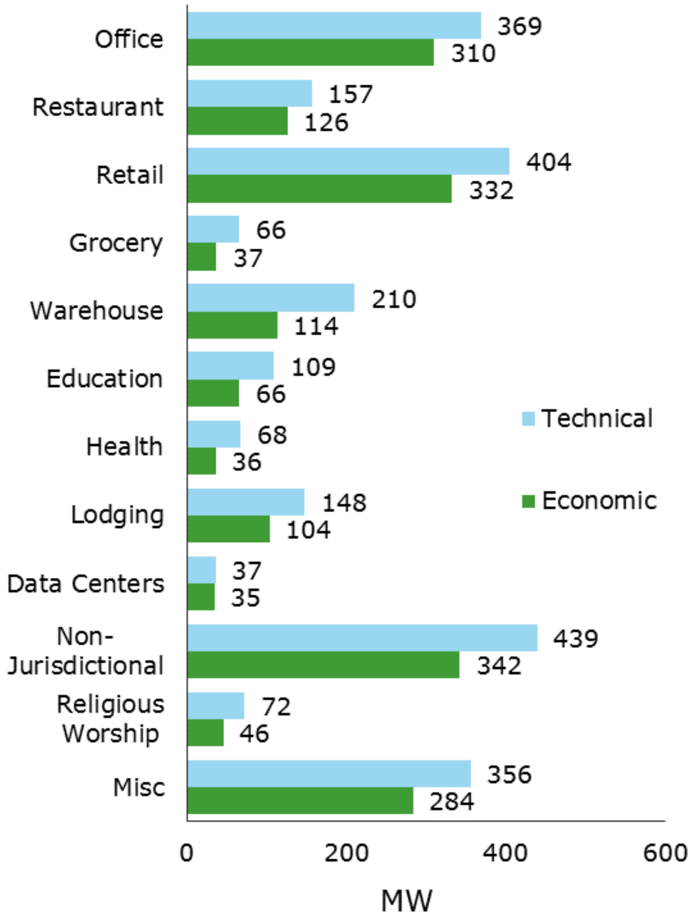


Table 24 also presents energy and demand savings potential by building type.

Table 24. Energy and Demand Savings Potential by Non-Residential Building Type

Non-Residential Building Type	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Office	1,500	1,164	369	310
Restaurant	612	444	157	126
Retail	1,399	1,057	404	332
Grocery	369	201	66	37
Warehouse	946	597	210	114
Education	584	289	109	66
Health	317	183	68	36
Lodging	593	362	148	104
Data Centers	224	216	37	35
Non-Jurisdictional	2,008	1,434	439	342
Religious Worship	306	127	72	46

Non-Residential Building Type	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Misc	1,718	1,257	356	284

5.2.6 Potentials by End Use

5.2.6.1 Residential

Figure 24 and Figure 25 show the end-use breakdown of residential potential.

Figure 24. Energy Savings Potential by Residential End Use

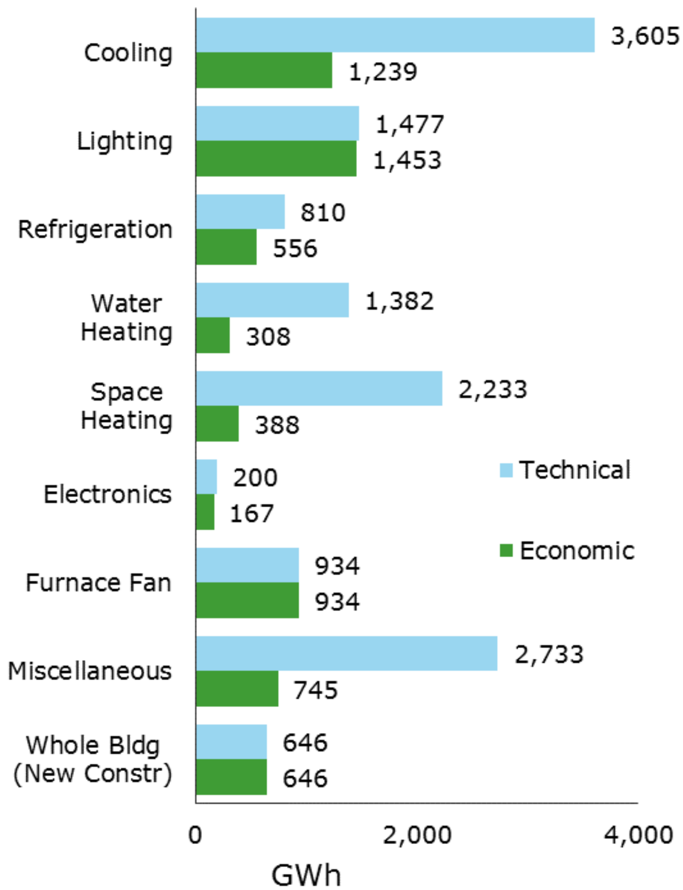


Figure 25. Demand Savings Potential by Residential End Use

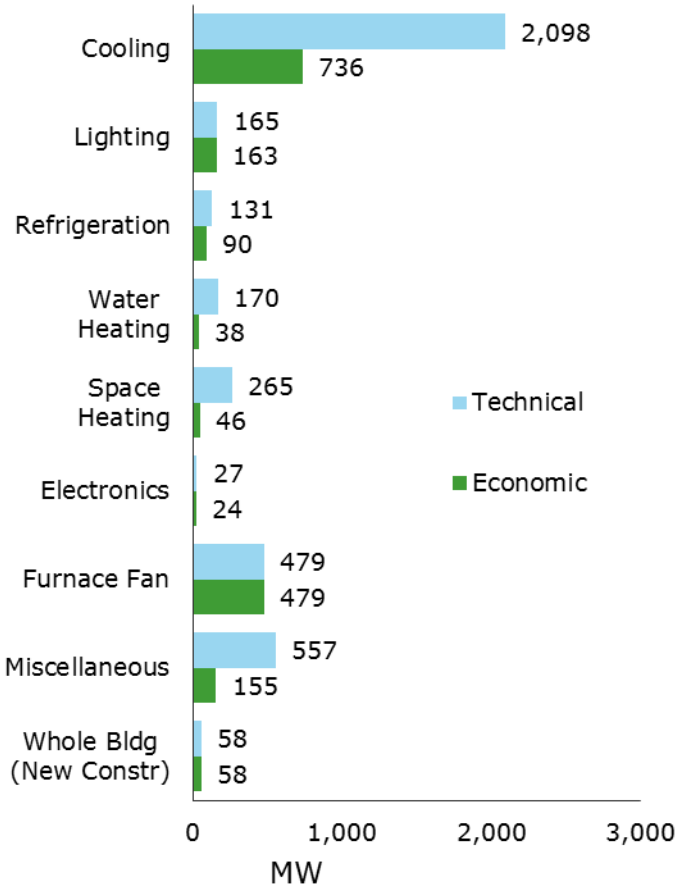


Table 25 shows the share each end use contributes to the economic potential for both energy and demand savings. Cooling remains largest contributor to both energy savings and peak demand technical savings potential. Space heating and water heating also have large technical energy savings potential, but lighting has the largest economic energy savings potential of all the residential end-uses. For residential peak demand, cooling and furnace fans have the largest economic peak demand potential.

Table 25. Energy and Demand Savings Potential by Residential End Use

Residential End Use	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Cooling	3,605	1,239	2,098	736
Lighting	1,477	1,453	165	163
Refrigeration	810	556	131	90
Water Heating	1,382	308	170	38
Space Heating	2,233	388	265	46
Electronics	200	167	27	24
Furnace Fan	934	934	479	479
Miscellaneous	2,733	745	557	155

Residential End Use	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Whole Bldg (New Constr)	646	646	58	58

*Sums from this table will not match previous tables due to rounding errors.

5.2.6.2 Non-Residential

Figure 26 and Figure 27 show energy and demand savings by non-residential end use.

Figure 26. Energy Savings Potential by Non-Residential End Use

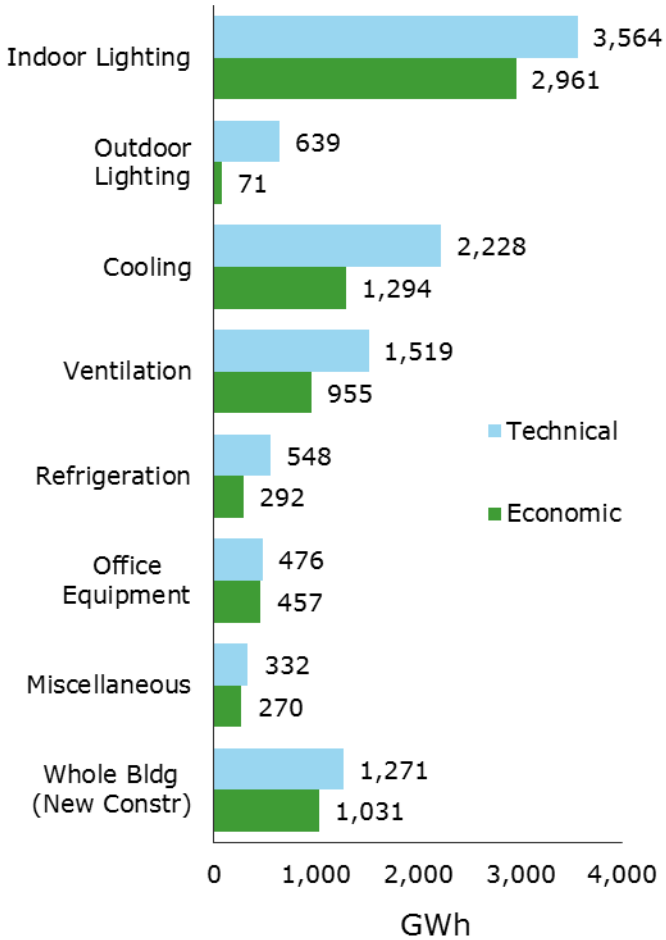
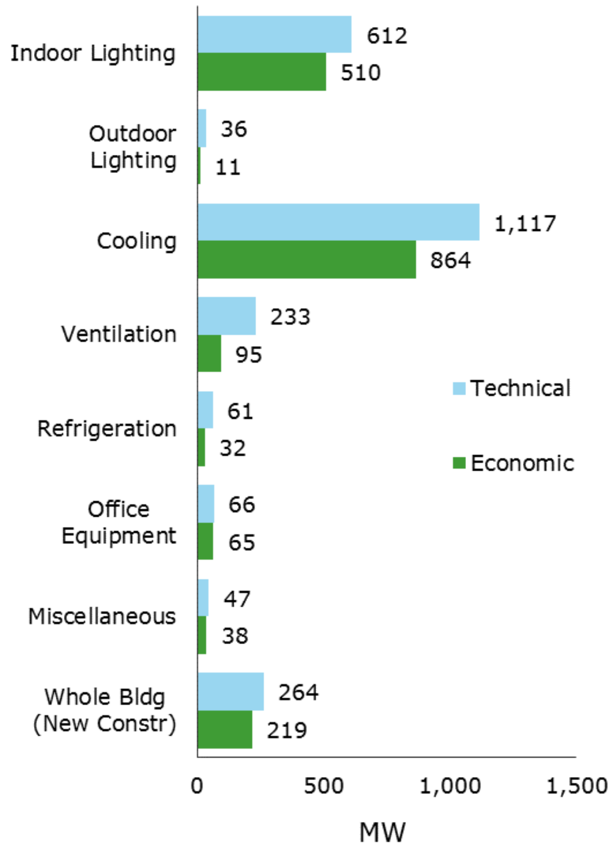


Figure 27. Demand Savings Potential by Non-Residential End Use



Similarly, Table 26 shows the contribution to savings from each end use. Energy savings potential is greatest in lighting, followed by cooling.[20]

Table 26. Energy and Demand Savings Potential by Non-Residential End Use

Non-Residential End Use	Energy (GWh)		Demand (MW)	
	Technical	Economic	Technical	Economic
Indoor Lighting	3,564	2,961	612	510
Outdoor Lighting	639	71	36	11
Cooling	2,228	1,294	1,117	864
Ventilation	1,519	955	233	95
Refrigeration	548	292	61	32
Office Equipment	476	457	66	65
Miscellaneous	332	270	47	38
Whole Bldg (New Construction)	1,271	1,031	264	219

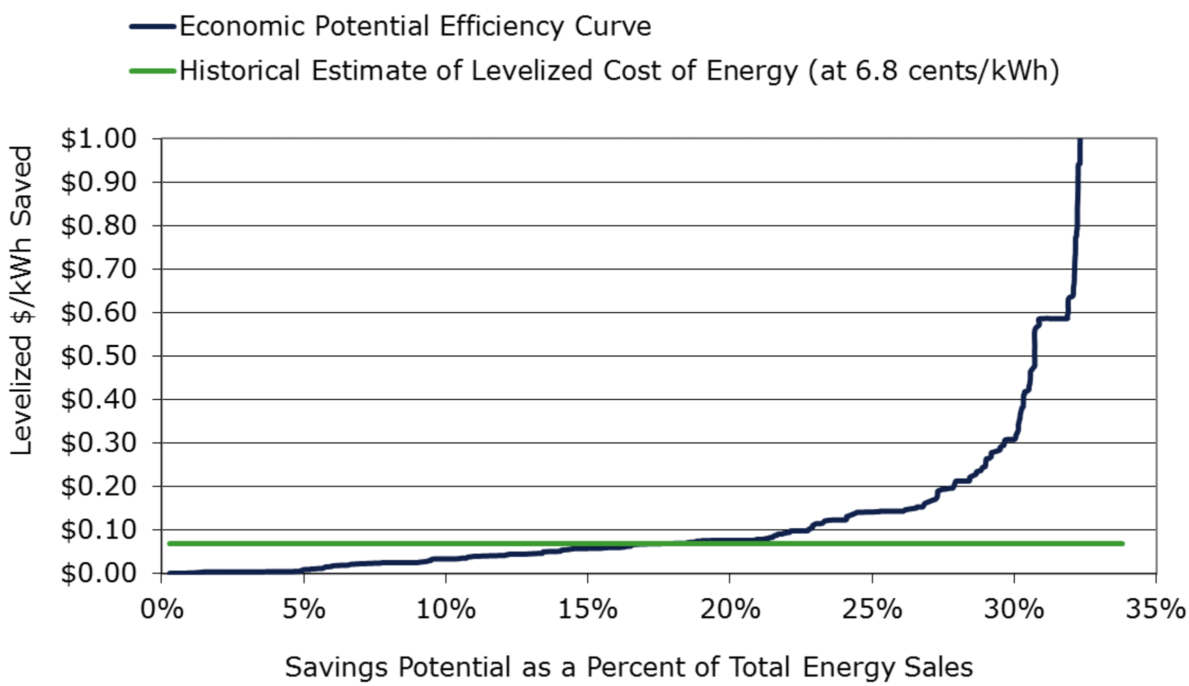
[20] It should be noted that that Dominion already has programs in place that target non-residential lighting, HVAC and ventilation but this study finds that additional potential remains in these end uses.

5.2.7 Energy Efficiency Supply Curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy efficiency supply curve. A supply curve is typically depicted on two axes: one captures the cost per unit of saved energy (e.g., levelized $/kWh saved), and the other shows energy savings at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that precede them. The costs of the measures are levelized over the life of the savings achieved. In this portion of the analysis, these costs are only referring to measure costs, and not the full cost of implementing these measures through a Dominion program.

Figure 28 presents the supply curves constructed for this study for electric energy efficiency. It represents the ordered set of efficiency measures in terms of their savings as a percentage of total energy sales.[21] The purpose of these curves is to show how much potential (as a percent of base usage) can be realized (on the horizontal axis) compared to a scale of levelized costs (on the vertical axis), including measures that are not cost-effective. Historically, Dominion's levelized cost is estimated at approximately 6.8 cents per kWh and is shown on the chart in green. The economic potential of measures which can deliver savings at that levelized cost of energy represent approximately 17% of total energy sales.

Figure 28. Energy Savings Potential as a Percent of Total Sales



[21] For readability, this graph only presents measures with a savings potential of less than $1 per kWh.

5.2.8 Top 20 Saving Measures

Table 27 through Table 34 show the top 20 measures for energy and demand savings potential in the residential and non-residential sectors. For each section, the first table shows the top 20 measures as ranked by technical potential savings. The following table then shows the top 20 measures ranked by economic savings. All measures with a TRC less than one are not considered as part of the economic potential and thus were not carried over to the top 20 economic measures tables.

In both sectors, LEDs are prevalent among the top energy saving measures despite the impact of tightening lighting standards. In terms of demand impacts, cooling based measures (such as furnace fans, heat pumps, and DX packaged systems) provide a large contribution to potential demand savings.

5.2.8.1 Residential

Table 27 through Table 30 show the top 20 measures by technical energy potential, economic energy potential, technical demand potential, and economic demand potential, respectively.

Table 27. Top 20 Measures Contributing to Residential Technical Energy Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
Direct Feedback	Single Family	935	1.0	0
ECM Furnace Fan (variable speed motor) - Cooling	Single Family	907	5.1	907
Heat Pump Dryer	Single Family	636	0.1	0
Heat Recovery Ventilators (HP heating)	Single Family	575	0.5	0
2nd Refrigerator Recycling	Single Family	566	2.6	566
Solar Domestic Water Heating	Single Family	549	0.5	0
Indirect Feedback	Single Family	421	1.5	421
LEDs (base Halogen (Specialty) 2.5 hrs/day) Midstream, >2021	Single Family	321	260.5	321
17 SEER (12.28 EER) Split-System Air Conditioner (CAC)	Single Family	300	0.7	0
Heat Pump Water Heater - Energy Star - Early Replacement	Single Family	287	1.0	0
Whole House Fans (HP cooling)	Single Family	271	1.0	0
High Efficiency CD (EF=3.01 w/moisture sensor)	Single Family	238	1.6	238
LED Tube replacement for fluorescent lamps	Single Family	224	1.2	224
Proper Sizing and Quality Install (CAC)	Single Family	218	0.9	0
LEDs (base Halogen (Specialty) 6 hrs/day) Midstream, >2021	Single Family	212	391.9	212
Heat Pump Water Heater - Energy Star	Single Family	197	0.9	0
Ground Source Heat Pump with Desuperheater (HP heating)	Single Family	181	0.0	0
Air Source Heat Pump (resistance heating)	Single Family	178	3.4	178
Proper Refrigerant Charging and Air Flow (CAC)	Single Family	174	1.9	174
Cool Roof (HP cooling)	Single Family	173	1.2	173

Table 28. Top 20 Measures Contributing to Residential Economic Energy Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
ECM Furnace Fan (variable speed motor) - Cooling	Single Family	907	5.1	907
2nd Refrigerator Recycling	Single Family	566	2.6	566
Indirect Feedback	Single Family	421	1.5	421
LEDs (base Halogen (Specialty) 2.5 hrs/day) Midstream, >2021	Single Family	321	260.5	321
High Efficiency CD (EF=3.01 w/moisture sensor)	Single Family	238	1.6	238
LED Tube replacement for fluorescent lamps	Single Family	224	1.2	224
LEDs (base Halogen (Specialty) 6 hrs/day) Midstream, >2021	Single Family	212	391.9	212
Air Source Heat Pump (resistance heating)	Single Family	178	3.4	178
Proper Refrigerant Charging and Air Flow (CAC)	Single Family	174	1.9	174
Cool Roof (HP cooling)	Single Family	173	1.2	173
LEDs (base Halogen (Specialty) 2.5 hrs/day) 2021 onward	Single Family	138	16.7	138
Proper Refrigerant Charging and Air Flow (HP cooling)	Single Family	128	1.7	128
Whole House Fans (CAC early replacement)	Single Family	126	1.2	126
Energy Star LCD TV	Single Family	120	12.2	120
LEDs (base Halogen 2.5 hrs/day) Midstream, >2021	Single Family	104	6.8	104
LEDs (base Halogen (Specialty) 6 hrs/day) 2021 onward	Single Family	91	25.1	91
DHW Tank Wrap	Single Family	80	1.1	80
Cool Roof (CAC early replacement)	Single Family	80	1.5	80
LEDs (base Halogen (Specialty) 0.5 hrs/day) Midstream, >2021	Single Family	78	52.1	78
ECM Furnace Fan (variable speed motor) - Cooling	Multifamily	75	4.5	75

Table 29. Top 20 Measures Contributing to Residential Technical Demand Savings Potential

Measure Name	Building Type	Technical MW	Measure TRC	Economic MW
ECM Furnace Fan (variable speed motor) - Cooling	Single Family	465	5.1	465
Direct Feedback	Single Family	232	1.0	0
17 SEER (12.28 EER) Split-System Air Conditioner (CAC)	Single Family	178	0.7	0
Whole House Fans (HP cooling)	Single Family	161	1.0	0
Heat Pump Dryer	Single Family	108	0.1	0
Indirect Feedback	Single Family	104	1.5	104
Proper Refrigerant Charging and Air Flow (CAC)	Single Family	104	1.9	104
Cool Roof (HP cooling)	Single Family	103	1.2	103
WINDOWS - Default With Sunscreen (CAC)	Single Family	93	0.4	0
2nd Refrigerator Recycling	Single Family	92	2.6	92
Proper Sizing and Quality Install (CAC)	Single Family	90	0.9	0
Proper Refrigerant Charging and Air Flow (HP cooling)	Single Family	76	1.7	76
Whole House Fans (CAC early replacement)	Single Family	75	1.2	75
Ground Source Heat Pump with Desuperheater (HP cooling)	Single Family	71	0.1	0
Heat Recovery Ventilators (HP heating)	Single Family	68	0.5	0
Solar Domestic Water Heating	Single Family	68	0.5	0
Heat pump upgrade to (16+ SEER, 8.7+ HSPF) (HP cooling)	Single Family	64	0.7	0
15 SEER Split-System Air Conditioner w/ Quality Install - Early Replacement	Single Family	56	0.5	0
Cool Roof (CAC early replacement)	Single Family	48	1.5	48
Comprehensive Shell Air Sealing - Inf. Reduction (CAC)	Single Family	45	0.5	0

Table 30. Top 20 Measures Contributing to Residential Economic Demand Savings Potential

Measure Name	Building Type	Technical MW	Measure TRC	Economic MW
ECM Furnace Fan (variable speed motor) - Cooling	Single Family	465	5.1	465
Indirect Feedback	Single Family	104	1.5	104
Proper Refrigerant Charging and Air Flow (CAC)	Single Family	104	1.9	104
Cool Roof (HP cooling)	Single Family	103	1.2	103
2nd Refrigerator Recycling	Single Family	92	2.6	92
Proper Refrigerant Charging and Air Flow (HP cooling)	Single Family	76	1.7	76
Whole House Fans (CAC early replacement)	Single Family	75	1.2	75
Cool Roof (CAC early replacement)	Single Family	48	1.5	48
10% better than Energy Star Dehumidifier ROB (35-45 pints/day)	Single Family	42	11.9	42
Proper Refrigerant Charging and Air Flow (CAC early replacement)	Single Family	41	2.2	41
High Efficiency CD (EF=3.01 w/moisture sensor)	Single Family	40	1.6	40
ECM Furnace Fan (variable speed motor) - Cooling	Multifamily	39	4.5	39
Heat pump upgrade to (15 SEER, 8.2+ HSPF) (HP cooling Early Replacement)	Single Family	38	2.6	38
LEDs (base Halogen (Specialty) 2.5 hrs/day) Midstream, >2021	Single Family	36	260.5	36
LED Tube replacement for fluorescent lamps	Single Family	25	1.2	25
Door Weatherization (CAC)	Single Family	24	2.0	24
LEDs (base Halogen (Specialty) 6 hrs/day) Midstream, >2021	Single Family	24	391.9	24
Air Source Heat Pump (resistance heating)	Single Family	21	3.4	21
Door Weatherization (HP cooling)	Single Family	18	1.8	18
Energy Star LCD TV	Single Family	17	12.2	17

5.2.8.2 Non-Residential

Table 31 through Table 34 show the top 20 measures by technical energy potential, economic energy potential, technical demand potential, and economic demand potential, respectively.

Note that we included potential for non-jurisdictional buildings in our estimates of technical and economic potential. This building type represents a disproportionate share of our top 20, probably due to lower measure penetrations as these buildings are not targeted by programs.

Table 31. Top 20 Measures Contributing to Non-Residential Technical Energy Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
LEDs (base incandescent flood) >2021	Misc	390	23.3	390
LEDs (base incandescent flood) >2021	Retail	351	15.5	351
LEDs (base incandescent flood) >2021	Office	348	17.1	348
High Bay Bi-Level Programmed LED Fixture	Warehouse	312	17.3	312
LEDs (base incandescent flood) >2021	Non-Jurisdictional	231	24.9	231
DX Packaged System, EER=13.4, 10 tons	Retail	153	4.3	153
High Bay Bi-Level Programmed LED Fixture	Non-Jurisdictional	152	19.6	152
Variable Speed Drive Control, 5 HP	Retail	144	3.1	144
DX Packaged System, EER=13.4, 10 tons	Office	141	4.9	141
DX Packaged System, EER=13.4, 10 tons	Non-Jurisdictional	139	3.3	139
Variable Speed Drive Control, 5 HP	Misc	131	1.2	131
LED Outdoor Area Lighting	Non-Jurisdictional	104	0.6	-
ROB 4L4' LED Tube, >2021	Non-Jurisdictional	100	0.7	-
High Bay Bi-Level Programmed LED Fixture	Misc	97	19.2	97
Duct Testing/Sealing - Chiller	Non-Jurisdictional	86	0.6	-
DX Packaged System, EER=13.4, 10 tons	Misc	85	4.7	85
Variable Speed Drive Control, 15 HP	Misc	85	0.9	-
Variable Speed Drive Control, 5 HP	Non-Jurisdictional	83	2.0	83
Variable Speed Drive Control, 40 HP	Misc	79	0.6	-
DX Packaged System, EER=13.4, 10 tons	Lodging	79	2.9	79

Table 32. Top 20 Measures Contributing to Non-Residential Economic Energy Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
LEDs (base incandescent flood) >2021	Misc	390	23.3	390
LEDs (base incandescent flood) >2021	Retail	351	15.5	351
LEDs (base incandescent flood) >2021	Office	348	17.1	348
High Bay Bi-Level Programmed LED Fixture	Warehouse	312	17.3	312
LEDs (base incandescent flood) >2021	Non-Jurisdictional	231	24.9	231
DX Packaged System, EER=13.4, 10 tons	Retail	153	4.3	153
High Bay Bi-Level Programmed LED Fixture	Non-Jurisdictional	152	19.6	152
Variable Speed Drive Control, 5 HP	Retail	144	3.1	144
DX Packaged System, EER=13.4, 10 tons	Office	141	4.9	141
DX Packaged System, EER=13.4, 10 tons	Non-Jurisdictional	139	3.3	139
Variable Speed Drive Control, 5 HP	Misc	131	1.2	131
High Bay Bi-Level Programmed LED Fixture	Misc	97	19.2	97
DX Packaged System, EER=13.4, 10 tons	Misc	85	4.7	85
Variable Speed Drive Control, 5 HP	Non-Jurisdictional	83	2.0	83
DX Packaged System, EER=13.4, 10 tons	Lodging	79	2.9	79
DX Packaged System, EER=13.4, 10 tons	Restaurant	78	7.4	78
Data Center Improved Operations	Data Centers	77	126.9	77
RET Occ & Daylight Integral Sensor LED troffer (base 4L4'T8), >2021	Non-Jurisdictional	76	1.6	76
RET Occ & Daylight Integral Sensor LED troffer (base 4L4'T8), >2021	Office	74	1.1	74
Variable Speed Drive Control, 5 HP	Office	73	3.3	73

Table 33. Top 20 Measures Contributing to Non-Residential Technical Demand Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
LEDs (base incandescent flood) >2021	Misc	126	4.3	126
LEDs (base incandescent flood) >2021	Retail	102	3.3	102
LEDs (base incandescent flood) >2021	Office	99	4.9	99
High Bay Bi-Level Programmed LED Fixture	Warehouse	73	23.3	73
LEDs (base incandescent flood) >2021	Non-Jurisdictional	71	17.1	71
DX Packaged System, EER=13.4, 10 tons	Retail	70	15.5	70
High Bay Bi-Level Programmed LED Fixture	Non-Jurisdictional	66	4.7	66
Variable Speed Drive Control, 5 HP	Retail	52	0.4	-
DX Packaged System, EER=13.4, 10 tons	Office	49	7.4	49
DX Packaged System, EER=13.4, 10 tons	Non-Jurisdictional	48	2.9	48
Variable Speed Drive Control, 5 HP	Misc	45	24.9	45
High Bay Bi-Level Programmed LED Fixture	Misc	44	17.3	44
DX Packaged System, EER=13.4, 10 tons	Misc	42	2.1	42
Variable Speed Drive Control, 5 HP	Non-Jurisdictional	35	3.7	35
DX Packaged System, EER=13.4, 10 tons	Lodging	28	2.0	28
DX Packaged System, EER=13.4, 10 tons	Restaurant	25	2.1	25
Data Center Improved Operations	Data Centers	22	2.4	22
RET Occ & Daylight Integral Sensor LED troffer (base 4L4'T8), >2021	Non-Jurisdictional	22	19.6	22
RET Occ & Daylight Integral Sensor LED troffer (base 4L4'T8), >2021	Office	20	4.2	20
Variable Speed Drive Control, 5 HP	Office	20	0.1	-

Table 34. Top 20 Measures Contributing to Non-Residential Economic Demand Savings Potential

Measure Name	Building Type	Technical GWh	Measure TRC	Economic GWh
DX Packaged System, EER=13.4, 10 tons	Retail	126	4.3	126
DX Packaged System, EER=13.4, 10 tons	Non-Jurisdictional	102	3.3	102
DX Packaged System, EER=13.4, 10 tons	Office	99	4.9	99
LEDs (base incandescent flood) >2021	Misc	73	23.3	73
LEDs (base incandescent flood) >2021	Office	71	17.1	71
LEDs (base incandescent flood) >2021	Retail	70	15.5	70
DX Packaged System, EER=13.4, 10 tons	Misc	66	4.7	66
DX Packaged System, EER=13.4, 10 tons	Restaurant	49	7.4	49
DX Packaged System, EER=13.4, 10 tons	Lodging	48	2.9	48
LEDs (base incandescent flood) >2021	Non-Jurisdictional	45	24.9	45
High Bay Bi-Level Programmed LED Fixture	Warehouse	44	17.3	44
Economizer Repair - DX	Retail	42	2.1	42
Centrifugal Chiller, 0.51 kW/ton, 500 tons	Non-Jurisdictional	35	3.7	35
DX Packaged System, EER=13.4, 10 tons	School	28	2.0	28
HE PTAC, EER=9.6, 1 ton	Misc	25	2.1	25
Economizer Repair - DX	Office	22	2.4	22
High Bay Bi-Level Programmed LED Fixture	Non-Jurisdictional	22	19.6	22
DX Packaged System, EER=13.4, 10 tons	Health	20	4.2	20
Cool Roof - DX	Warehouse	19	1.4	19
DX Packaged System, EER=13.4, 10 tons	Religious Worship	18	2.3	18

5.2.9 Cross-study comparison of technical and economic results

In this section, we compare the results of the current study to the 2014 Dominion Potential study. The current study is based on residential saturation data collected in 2016, while the 2014 study used data from a 2013 survey. Dominion's customer base has grown, and the mix of residential and commercial customers has shifted. The market penetration of many measures increased. Dramatic changes occurred in the lighting market as prices of LEDs have declined dramatically since the lighting standards of the Energy Independence and Security Act (EISA) of 2007 went into effect between 2012 and 2014. Dominion's avoided costs have changed, affecting which measures are cost effective under the TRC test.

For each of the 10-year studies, we used base energy use at the end of the forecast period for savings comparisons: 2023 for the 2014 study and 2027 for the current study. We accounted for the accumulated effects of new construction over those 10 years in both potentials and base use. The difference in years accounts for a small portion of the change in the study results, as the number of customers, and corresponding base use, is expected to grow between 2023 and 2027. The reader should keep this difference in mind during the discussion below.

Figure 29 compares the results of the 2014 potential study to the current study, including base energy use, technical potential, and economic potential (plotted on left axis). The yellow triangles indicate the percent of base energy use represented by the potential estimates (plotted on right axis). The current study estimates a higher base use by 2027 than was forecast in the 2014 study for 2023 (72,742 GWh vs. 64,425). There was almost no change to the technical potential estimate, although because of the change to the base use forecast, it represents a smaller share of base use. Economic potential declined by 4%.

Figure 29. Comparison of Technical and Economic Potential: 2017 Study vs 2014 Study

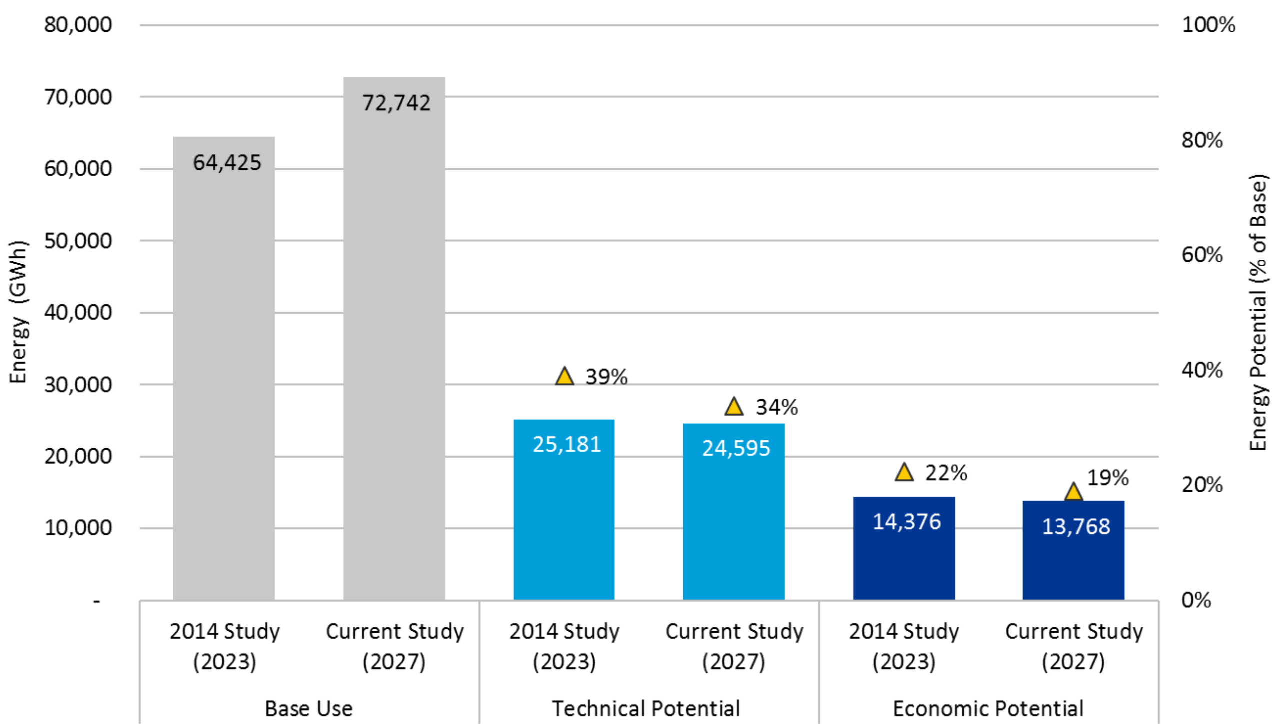
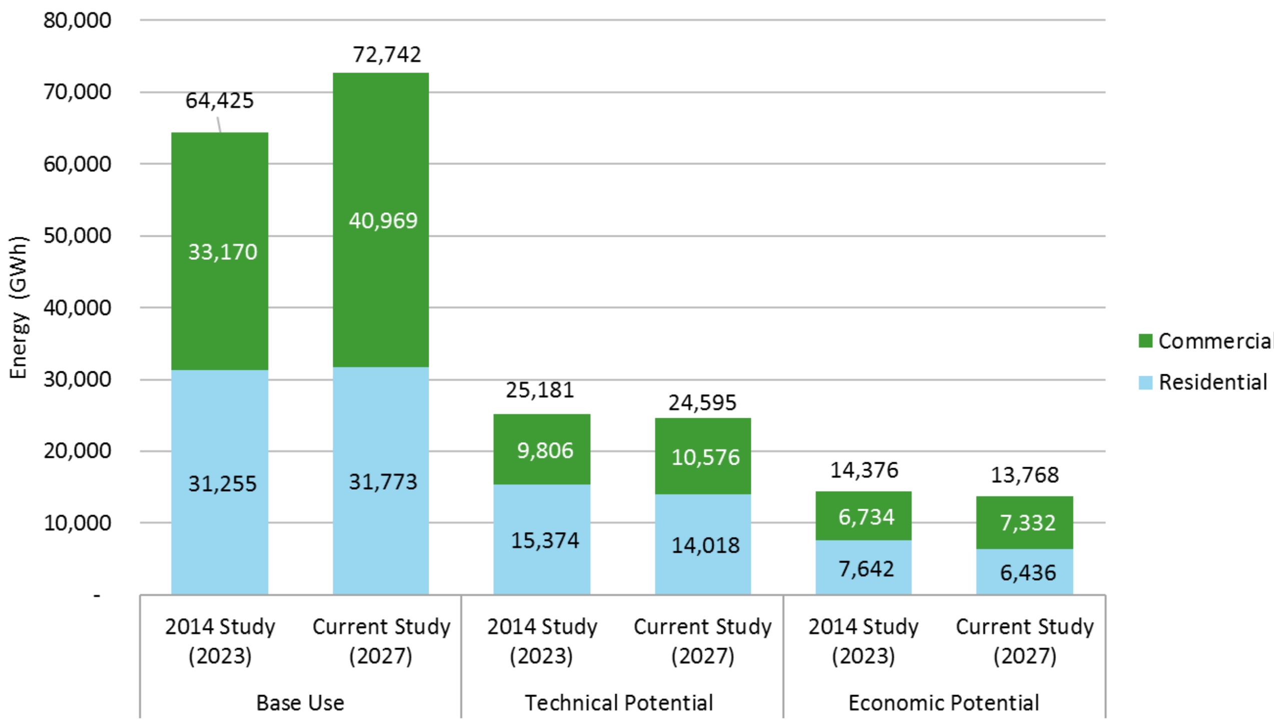


Figure 30 shows the same comparison broken out by sector. Most of the growth in base use is due to changes in the commercial forecast, and technical and economic potential for the commercial sector has increased, while residential potential has declined.

Figure 30. Comparison of Technical and Economic Potential by Sector: 2017 Study vs 2014 Study



5.3 Achievable (Program) Potential Results

This section provides a high-level summary of the achievable potential analysis, based on the results of the technical and economic potential analyses. This achievable analysis was conducted using the results of the base avoided cost scenario, and excludes opt-out, exempt, and non-jurisdictional customers. Although savings from these customers were included in the technical and economic results, they are excluded from the program achievable potential as they do not participate in Dominion programs and therefore should not be included in the estimation of program potential.

In contrast to the technical and economic potential estimates that are based on measure-level costs and savings, our estimates of achievable potential take into account market and other factors that affect the adoption of efficiency measures. As further described in Section 4 and Appendix A of this report, our method of estimating measure adoption takes into account market barriers and program incentives and reflects actual consumer and business implicit discount rates. This portion of the analysis also includes program budgets as they impact the savings potential and are used in the analysis of the total resource cost and other cost benefit tests. The discount rate assumptions can be found in Appendix C of the report, while annual budget assumptions can be found in Appendix I of the report.

In this analysis, achievable potential refers to the amount of savings that would occur in response to one or more specific program interventions. Gross or total market savings shown in this section includes net savings and savings attributable to program free-riders – those customers who would have installed the measure in the absence of the program. Net or program savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention.

The achievable analysis typically begins by calibrating budgets and savings to recent program results.[22] After the calibration is complete, all cost-effective measures from the technical and economic analysis are included in the model, and administrative and marketing budgets are increased to account for the additional measures.

DNV GL calibrated model parameters to produce energy savings and incentive expenditures consistent with Dominion's 2016 programs setting marketing and administrative expenses to match Dominion's 2016 budgets. The model parameters adjusted in this process represent such things as much it costs to reach a customer through marketing efforts, what the maximum annual uptake is for each measure, and how accepting or resistant the market is to a particular measure (market barriers). The resulting calibrations closely represented Dominion's program experience.

Because achievable potential depends on the type and degree of intervention applied, we developed potential estimates under alternative funding scenarios: Base+, 50% incentives and 75% incentives.[23] We estimated program energy and peak demand savings under each scenario for the 2018-2027 period. Per the direction of Dominion, we then modeled the incentive scenarios, defined as follows:

- Base+: We assume that program funding remains constant, but with incentives available for the full set of efficiency levels, set to levels equal to nearest like-measures.
- 50% incentives: We assume customer incentives are set at 50% of incremental costs.
- 75% incentives: We assume customer incentives are offered at the midpoint between the 50% incentive and a 100% incentive. Program budgets were increased in conjunction with the increased incentive spending.

Table 35 shows the results of the achievable analysis as compared to base consumption, technical potential, and economic potential. Energy savings estimates range from 3% for Base+ to 6% of base consumption under the 75% scenario.[24] Overall energy savings under the 75% scenario are projected to be 30% of economic potential. As a percent of base consumption, the Dominion results are lower than results seen in other jurisdictions, largely due to Dominion's low avoided costs and rates. Low avoided costs result in fewer measures passing the cost effectiveness screening, while low rates reduce the customer's benefits from adopting a measure, resulting in lower measure penetrations.

22 The calibration stage only includes measures that can be mapped to Dominion programs. All cost-effective measures are included in the funding scenario analyses.

23 These scenarios reflect the percentage of incremental measure cost that is assumed to be paid in customer incentives.

24 Base use and all potentials exclude opt-out and exempt customers within Dominion's service territory. While technical and economic potentials include savings for non-jurisdictional customers, they were excluded from achievable potential.

Table 35. Ten Year Cumulative Potential – GWh

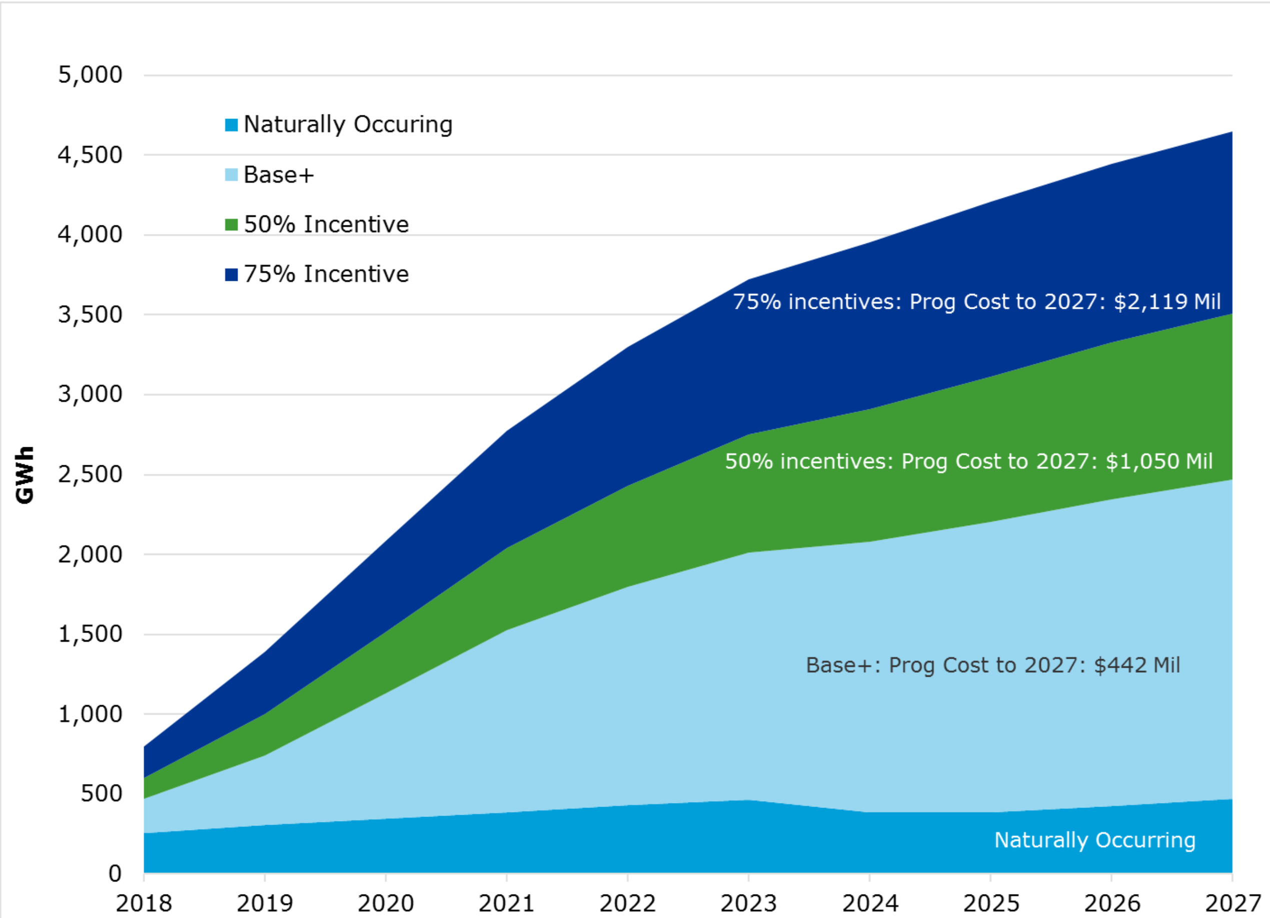
Sector	2027 Base Energy Use (GWH)	Ten Year Cumulative Potential - GWh				
		Technical Potential	Economic Potential	Base+	50% Achievable (Program)	75% Achievable (Program)
Residential	31,773	14,018	6,436	1,180	1,855	2,466
Savings % of Base		44%	20%	3.7%	5.8%	7.8%
Non-Residential	40,969	10,576	7,332	821	1,187	1,711
Savings % of Base		26%	18%	2.0%	2.9%	4.2%
Total	**72,742**	**24,595**	**13,768**	**2,001**	**3,042**	**4,177**
Savings % of Base		34%	19%	2.8%	4.2%	5.7%

5.3.1 Achievable (Program) Potential – Overall Results

Figure 31 shows our estimates of achievable potential savings over time. As shown in this figure, by 2027 cumulative net[25] energy savings are projected to be between 2,001 GWh under Base+ and 4,177 GWh under the 75% incentive scenario. In each scenario, savings increase over time. The figure includes the cumulative program cost over the 10-year forecast (including program and participant costs) associated with each scenario.

[25] Throughout this section, *net* refers to savings beyond those estimated to be naturally occurring; that is, from customer adoptions that would occur in the absence of any programs or standards.

Figure 31. Achievable Electric Energy Savings: All Evaluated Sectors



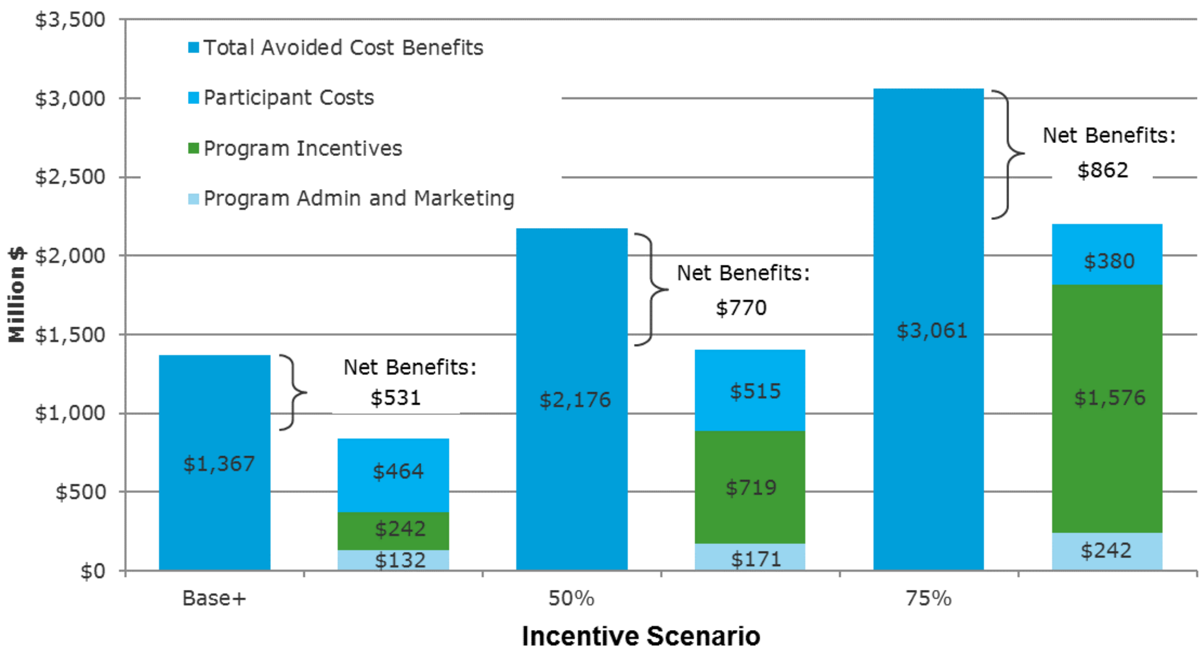
As incentive levels increase between program scenarios, the costs to administer and market the program also increase from additional programmatic activity. Increased incentives also affect participant costs as the incremental cost participants must pay per measure has decreased as a result of the higher incentives. It is also important to note that although the level of naturally occurring savings does not change between scenarios, program free riders receive the same incentives payments as program participants.

Figure 32 depicts the estimated costs and benefits under each funding scenario from 2018 to 2027. The present value of program costs (including program incentives[26],and program administration and marketing[27] but not participant costs) is $373 million under Base+, $891 million under 50% incentive scenario and $1,819 million under the 75% incentive scenario.

[26] The incentive budgets reported for this study are calculated by the model based on the penetration of the energy efficiency measures and the incentives paid.

[27]The administrative and marketing costs used in the analysis were based off the costs (indirect-other and direct implementation) from the EM&V indicator tables. These budgets were scaled up to account for the addition of other cost-effective measures in the analysis.

Figure 32. Benefits and Costs of Energy Efficiency Savings—2018-2027*



*PV (present value) of benefits and costs is calculated over the measure life for 2018-2027 program years, customer discount rate = 7.307%, utility discount rate = 6.307%, inflation rate = 1.98%

The present value of total avoided cost benefits ranges from $1,367 million under Base+ to $3,061 million under 75% incentives. All funding scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness.[28] The TRC benefit-cost ratios for Dominion's service territory are 1.6 for Base+, 1.5 for the 50% scenario and 1.4 under the 75% scenario.

Key results of our efficiency scenario forecasts from 2018 to 2027 are summarized in Table 36.

[28] Other cost benefit tests will be provided in the appendix of the draft report.

Table 36. Summary of Achievable Potential Results—2014-2027*

Result - Programs	Program Scenario:		
	Base+	50% Incentives	75% Incentives
Total Market Energy Savings - GWh (year 10 annual)	3,081	4,131	5,264
Total Market Peak Demand Savings - MW (year 10 annual)	578	961	1,298
Program Energy Savings - GWh (year 10 annual)	2,001	3,042	4,177
Program Peak Demand Savings - MW (year 10 annual)	395	772	1,109
Program Costs - Real, $ Million			
Administration (10-year total)	$60	$103	$182
Marketing (10-year total)	$96	$101	$106
Incentives (10-year total)	$286	$846	$1,831
Total Program Costs (10-year total)	$442	$1,050	$2,119
PV Avoided Costs (PV 10-year cost)	$1,367	$2,176	$3,061
PV Annual Program Costs (Adm/Mkt) (PV 10-year cost)	$132	$171	$242
PV Net Measure Costs (PV 10-year cost)	$705	$1,234	$1,957
Net Benefits (PV 10-year cost)	$531	$770	$862
TRC Ratio	1.6	1.5	1.4

*PV (present value) of benefits and costs is calculated over the life for 2018-2027 program years, customer discount rate = 7.307%, utility discount rate = 6.307%, inflation rate = 1.98%; GWh and MW savings are cumulative through 2027.

5.3.2 Breakdown of Achievable Potential by Sector

Cumulative net achievable potential estimates by sector for the period of 2018-2027 are presented in Figure 33 and Figure 34. These figures compare the residential and non-residential sector results for each funding scenario. All opt-out, exempt, and non-jurisdictional customers were excluded from this analysis.

Under the program assumptions developed for this study, achievable energy savings and peak demand savings are highest for the residential sector.[29]

[29] The estimates of peak demand savings are from the installation of energy efficiency measures and do not include demand savings from demand response technologies such as direct load control or dynamic pricing.

Figure 33. 2027 Net Achievable Energy Savings by Sector

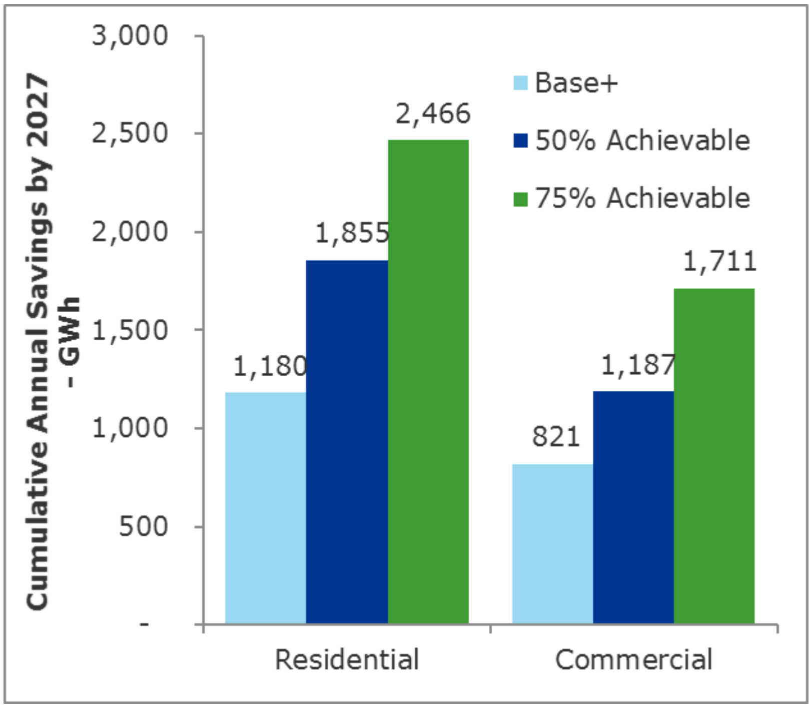


Figure 34. 2027 Net Achievable Peak-Demand Savings by Sector

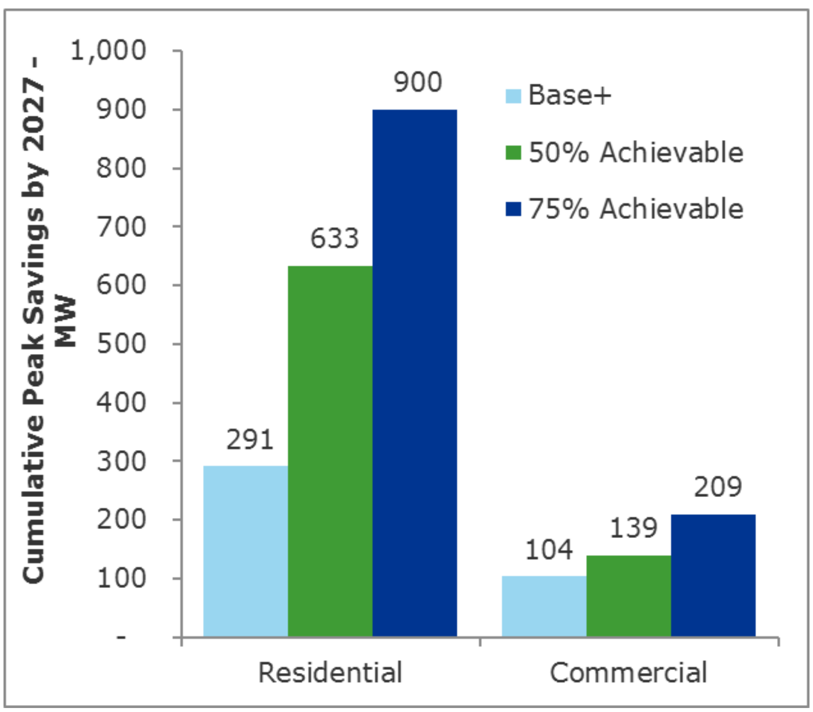


Figure 35 shows cumulative net achievable program savings for the total residential sector by program scenario. By 2027, net energy savings ranges from 1,180 GWh under Base+ to 2,466 GWh under the 75% incentive scenario.

Figure 35. 2027 Achievable Energy Savings: Residential Sector

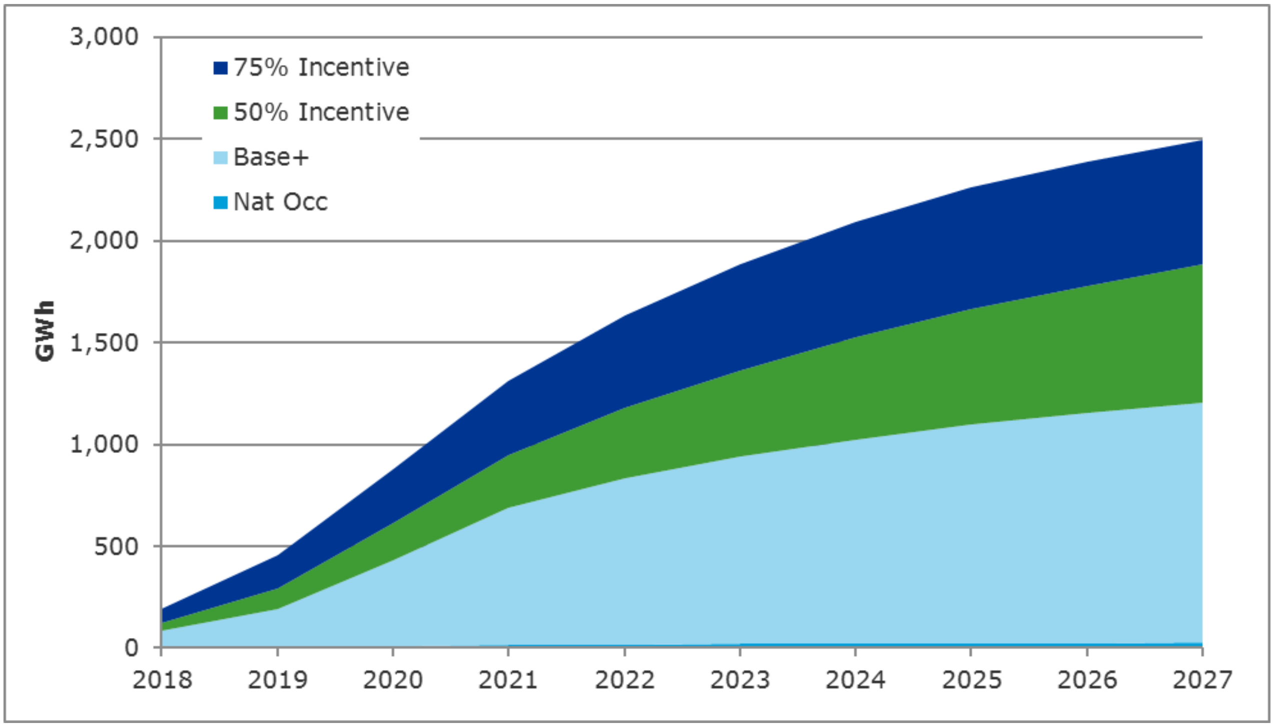
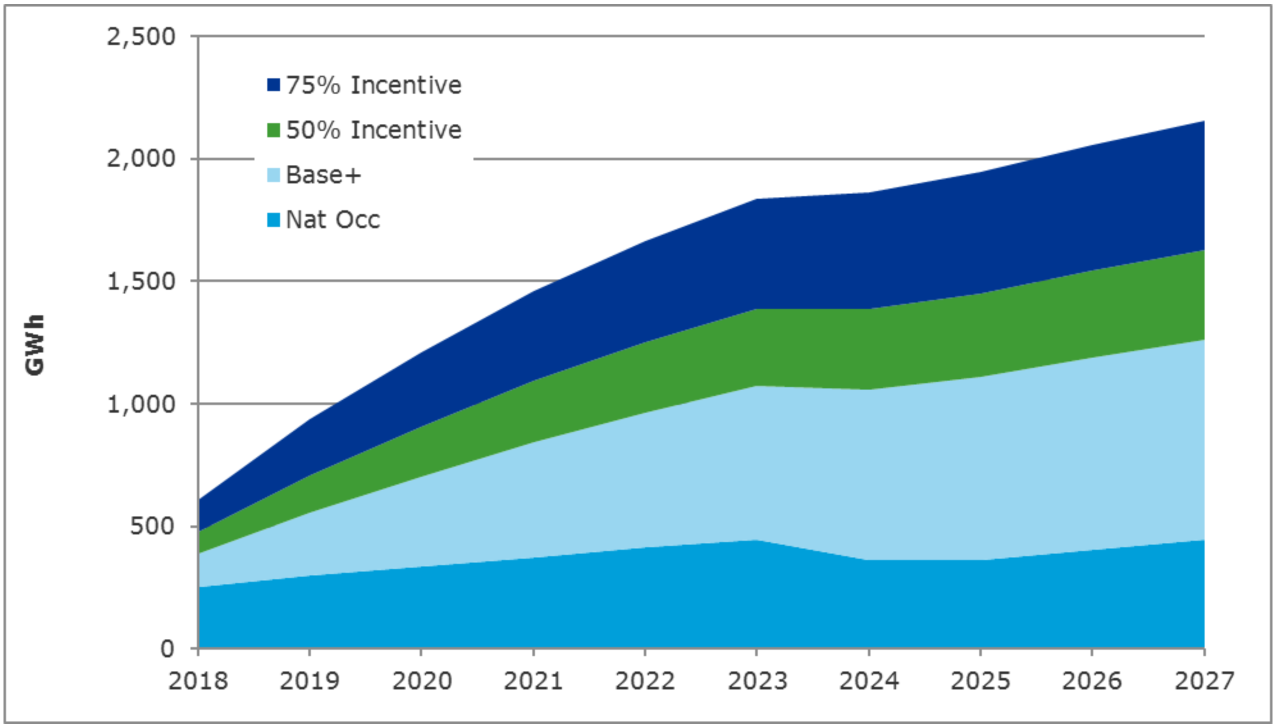


Figure 36 shows cumulative net achievable program savings by non-residential program scenario. By 2027, net energy savings reach 821 under Base+, 1,187 GWh under the 50% incentive scenario and 1,711 GWh under the 75% incentive scenario.

Figure 36. 2027 Achievable Energy Savings: Non-Residential Sector



5.3.3 Cross-study comparison of achievable results

In this section, we compare the results of the current study to the 2014 Dominion Potential study and to potential studies from other areas.

Figure 37 compares the results of the 2014 potential study to the current study, including technical potential, economic potential, and achievable potential for the 75% and 50% scenarios (plotted on left axis). The yellow triangles indicate the percent of base energy use represented by the potential estimates (plotted on right axis). Achievable potentials for the two incentive scenarios increased in absolute terms, but due to the change to the base use forecast (which increased from 64,425 to 72,742 GWh), the potential as a percent of base changed very little, with just a slight increase from 3 to 4% in the 50% scenario.

Figure 37. Comparison of Technical, Economic, and Achievable Potential: 2017 Study vs 2014 Study

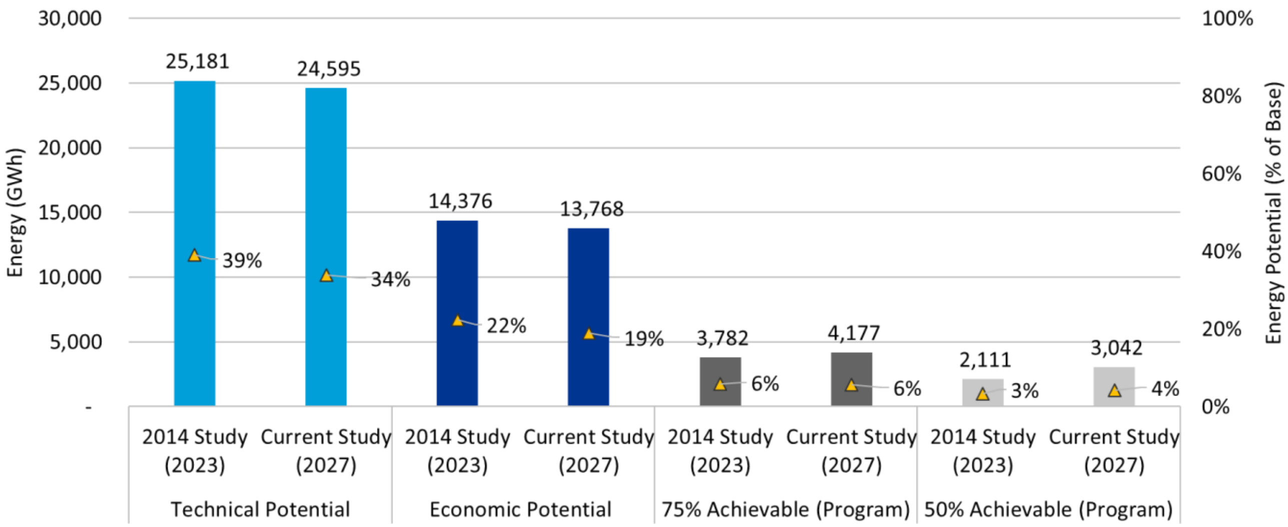
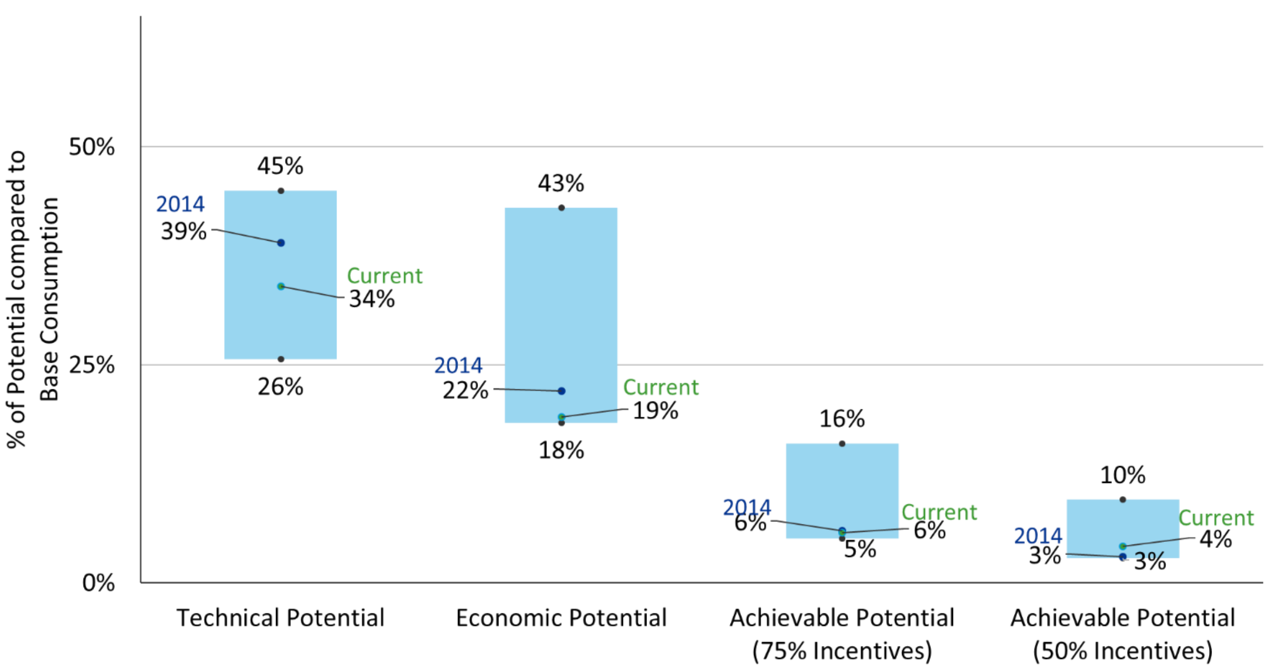


Figure 38 compares the results of the Dominion 2014 potential study and the current study to historical ranges of potential savings from other DNV GL studies. The blue bars indicate the range of potential from other DNV GL studies for technical, economic, 75% and 50% achievable scenarios. Dominion's technical potential is in the mid-range when compared to other studies. However, the economic and achievable potential is on the lower end of the spectrum, largely due to Dominion's low avoided costs and rates. As discussed above, low avoided costs result in fewer measures passing the cost effectiveness screening, while low rates reduce the customer's benefits from adopting a measure, resulting in lower measure penetrations.

Figure 38. Current Study Compared to Historical Ranges of Potential Savings



About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.

EXHIBIT TW/EM – 22

RESPONSE TO SIERRA CLUB 5-5

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fifth Set

The following response to Question No. 5 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 24, 2019 has been prepared under my supervision.

Deanna R. Kesler
Regulatory Consultant
Dominion Energy Services, Inc.

Question No. 5

Refer to Attachment Sierra Club Set 2-4 (DRK) (3), page 6; and Kesler Testimony, Schedule 7. In the potential study, the program savings potential with 50 percent incentives in the potential study are stated as 3,042 GWh from 2018-2027. The Company's system-level energy savings for 2019-2027 total 1,001 GWh by 2027. Please explain why the Company's proposed savings levels are only one-third of the potential study savings levels.

Response:

Schedule 7 to the pre-filed direct testimony of Company Witness Deanna R. Kesler shows the Company's system level energy savings from 2019 through 2027 for only the programs reflected in Schedule 7. This schedule does not include currently approved programs producing energy savings nor any future programs.

EXHIBIT TW/EM – 23

RESPONSE TO SIERRA CLUB 3-20

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 20 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No. 20

Refer to Hubbard's Testimony, at 11 and the response to Staff's question no 13. Please explain why the Residential Home Energy Assessment Program does not provide all envelope weatherization measures, including insulation and air sealing for basements, attics, and walls.

Response:

The measures incorporated into the Company's proposed Residential Home Energy Assessment Program were determined to be cost-effective based on an evaluation of their individual cost-benefit test scores, using the NEEP Mid-Atlantic TRM as the primary basis of projected energy savings. Some measures were considered and evaluated beyond those included in the final proposed Program design, but they ultimately were not incorporated into the final design because they were not cost-effective based on the results of the cost-benefit tests.

The Company further notes that Duct Sealing and Duct Insulation are included in the final proposed Program design, representing cost-effective envelope measures.

EXHIBIT TW/EM – 24

RESPONSE TO SIERRA CLUB 4-9

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 9 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

The following response to Question No. 9 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision as it pertains to legal matters.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 9

Refer to Hubbard's testimony. The following types of programs and measures do not appear to be included in the Company's proposed DSM filing. Please explain why these programs are not offered to customers. For each program identified below that is not included in the DSM filing, please provide any and all analyses undertaken regarding each program, including all relevant assumptions regarding the program design, costs, benefits, savings and cost-effectiveness.

a. A residential new construction program
b. A non-residential new construction program
c. A residential heating and/or cooling system replacement program
d. An "upstream buy down" program that addressed both residential and non-residential customers, through which incentives are provided to manufacturers and/or distributors to reduce the cost paid by consumers, rather than a rebate paid to the customer directly
e. A multi-family program that addresses both residential and non-residential building configurations

f. A small business program that addresses other businesses besides offices and small manufacturing (e.g., retail stores, restaurants, convenience stores, etc.)
g. A strategic energy management or continuous energy improvement program for non-residential customers beyond that addresses other businesses besides offices
h. An agricultural program

Response:

The Company objects to this request as overly broad, unduly burdensome, and not relevant or reasonably calculated to lead to this discovery of admissible evidence to the extent it seeks information outside the subject matter of the Company's application in this proceeding and to the extent it seeks "any and all analyses" about programs that may or may not have been considered in any given year going back to 2009. The Company further objects to this request to the extent it seeks information subject to attorney-client privilege and/or work doctrine protection. Subject to and notwithstanding these objections, the Company provides the following response.

In each of its DSM filings with the Commission, the Company uses information provided to it through the RFP process and uses its professional judgment based on a balance of relevant information available, regarding what programs are needed, cost-effective, likely to be approved by the Commission, and practical to implement. The Company notes that it welcomes input from stakeholders through the ten-year process created under the Grid Transformation and Security Act of 2018. The Company will use input from this stakeholder process in the development of RFPs issued to program designers and implementers for future DSM programs.

The Company also notes the following with respect to the specific program ideas noted in this request:

(a-b) Based on the Company's general experience and understanding, new construction programs present challenges in developing incentives that are sufficiently large enough to induce meaningful changes to building design while maintaining cost-effectiveness in light of current building codes and construction trends.

(c) Programs that incentivize full heating/cooling system replacement are also challenged by the need to provide an incentive that induces action while maintaining cost-effectiveness, particularly in light of increasingly stringent efficiency standards for heating and cooling equipment. The Company has previously addressed this challenge by incentivizing upgrades to heating and cooling systems in order to induce customers to install high efficiency equipment than they otherwise would have.

(d) The Company prefers where possible to focus on the retail customer, recognizing this is not always practical.

(e) Multi-family customers are not excluded from current low-income program offerings and have been included in some previous residential programs.

(f-h) The Company offers a small business program that does not restrict eligibility by business type. The cited business types are eligible for participation in this program. The Company has proposed in this current case to expand options available to businesses. The Company further proposes to continue offering other measures for non-residential customers, again, not restricted by business type. Agricultural customers are not excluded from the Company's non-residential programs.

The challenges noted herein exist in different forms for any potential program idea in that any given program (1) must provide an incentive that induces action, (2) have quantifiable energy and demand savings relative to current energy efficiency standards that can be rigorously accounted for, (3) can be tied in some way to the Company's customers, and (4) pass the relevant cost-effectiveness tests.

Regardless, the Company welcomes the opportunity to explore the possibility of new programs that either address the needs of specific customer segments or are targeted at any of the customer segments cited in the question, and looks forward to receiving such input through the stakeholder process.

EXHIBIT TW/EM – 25

RESPONSE TO SIERRA CLUB 4-10

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 10 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No. 10

Please clarify whether customers in multi-family buildings are eligible to participate in the Company's DSM programs. If yes, please indicate the programs such customers can participate.

Response:

The Company has two active residential DSM programs available for qualifying customers living in multi-family buildings: the Phase I AC Cycling Program and the Phase IV Residential Income and Age Qualifying Home Improvement Program. Additionally, the Company's EnergyShare Program is also available to qualifying customers living in multi-family homes.

EXHIBIT TW/EM – 26

SELECTION FROM ACEEE, THE NEW LEADERS OF THE PACK: ACEEE'S FOURTH NATIONAL REVIEW OF EXEMPLARY ENERGY EFFICIENCY PROGRAMS, REPORT U1901, JANUARY 2019

The New Leaders of the Pack: ACEEE's Fourth National Review of Exemplary Energy Efficiency Programs

Seth Nowak, Martin Kushler, and Patti Witte

January 2019
Report U1901

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About the Authors

Seth Nowak conducts analysis and writes reports on energy efficiency programs and policies in the electric and natural gas utility sector. Focus areas of his research include exemplary programs, best practices, and program evaluation, measurement, and verification.

Martin Kushler is a senior fellow at ACEEE, where he previously served as director of the utilities program for 10 years. He has been directing research and evaluation regarding energy efficiency and utilities for three decades, and has provided consultation to numerous states and the federal government. Prior to joining ACEEE, he directed the evaluation section at the Michigan Public Service Commission for 10 years.

Patti Witte is a research consultant to ACEEE. She has more than two decades of experience researching utility energy efficiency programs.

Acknowledgments

ACEEE thanks the following organizations for their funding support of this project: the Energy Foundation, Los Angeles Department of Water and Power, CenterPoint Energy, and Pacific Gas and Electric Company. The funders were not involved in the review or selection of the recognized programs.

ACEEE also thanks Margie Harris of Arcturus Consulting; Chris Neme of Energy Futures Group; and Ellen Zuckerman of the Southwest Energy Efficiency Project (SWEEP) and Schlegel and Associates for serving on the expert panel that reviewed program nominations. The panel members generously shared their expertise, rated programs, and advised ACEEE staff on selecting the programs recognized in this report. They were not aware of the project funders.

The authors also wish to thank ACEEE subject matter experts Dan York, Jennifer Amann, Ethan Rogers, and Grace Relf for reading and analyzing program nominations.

The authors gratefully acknowledge the external and internal reviewers who supported this report. External expert reviewers included Chris Neme and Ellen Zuckerman. External review and support do not imply affiliation or endorsement. Internal reviewers included Steve Nadel, Dan York, Marty Kushler, and Maggie Molina. Last, we would like to thank Fred Grossberg for developmental editing and managing the editing process; Keri Schreiner, Elise Marton, Mary Rudy, Roxanna Usher, and Sean O'Brien for copy editing; and Wendy Koch, Eric Schwass, Maxine Chikumbo, and Kate Doughty for their help in launching this report.

Executive Summary

BACKGROUND

ACEEE has reviewed utility-funded energy efficiency programs nationwide every five years since 2003 to identify trends and present effective approaches. Throughout this period, the energy efficiency industry has been evolving, adapting program designs and strategies in response to policy changes and technology advances.

Utility-sector energy efficiency programs are more important than ever. Energy efficiency continues to be one of the cleanest and lowest-cost utility system resources.[1]
This fourth ACEEE national review of exemplary energy efficiency programs has two objectives: (1) to identify and promulgate successful approaches that might help others improve their program designs and (2) to provide recognition to utilities and other administrators that are funding and delivering excellent programs.

We do not claim that the examples included in this report are absolutely the nation's best programs. It would not be feasible to assess all the programs in the United States, nor would that be necessary to meet our purposes in this project. The intent is to identify noteworthy programs that we feel to be exemplary and worthy of emulation.

METHODOLOGY

The methodology we used was similar to the first three national reviews. We issued a broad call for nominations of exemplary programs from people and organizations across the industry, reviewed the pool of nominations with the help of an expert panel, and selected the final set of exemplary programs based on program performance and expert opinions. Additional detail on the selection process is provided in the body of the report.

For a program to be eligible for nomination, we required that it be located in the United States or Canada; funded, at least in part, through utility rates, public benefits charges, or similar utility revenue mechanisms; and administered by a utility, government agency, third-party independent administrator, or a combination.

EXEMPLARY PROGRAMS

The most effective high-performance programs focus on various customer sectors, industries, and end uses. With this in mind, we present profiles of successful models in 14 program categories.

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[1] I. Hoffman, G. Leventis, and C. Goldman, *Trends in the Program Administrator Cost of Saving Electricity for Utility Customer-Funded Energy Efficiency Programs* (Berkeley: LBNL, 2017). eta-publications.lbl.gov/sites/default/files/lbnl-1007009.pdf. Lazard, *Lazard's Levelized Cost of Energy Analysis: Version 11.0.*, 2017. lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

Small Commercial

Commonwealth Edison, ComEd Energy Efficiency Program Small Business Offering, Illinois. Trade-ally-driven, prescriptive incentive approach for private businesses with less than 100 kW peak demand.

Consumers Energy, Small Business Energy Efficiency Solutions, Michigan. Multifaceted program including trade-ally-driven installations, walk-through assessments, and direct measure installation at little or no cost to small business and nonprofit customers.

New Jersey Board of Public Utilities, Office of Clean Energy, Direct Install Program, New Jersey. Technical assistance, education, and incentives up to 70% of the project cost for replacing lighting, HVAC, refrigeration, and other equipment with energy-efficient alternatives.

Xcel Energy, One-Stop Efficiency Shop, Minnesota. No-cost audit, below-market-rate financing, and rebates for lighting and RTU upgrades open to Xcel Energy commercial accounts in Minnesota with a demand of 400 kW or less.

Medium and Large Commercial and Industrial

Bonneville Power Administration, Energy Smart Industrial. Custom projects, strategic energy management (SEM), small industrial (SI), and lighting energy efficiency for 117 enrolled utilities and their industrial customers in seven Northwest states.

Focus on Energy, Large Energy Users Program, Wisconsin. Technical assistance, prescriptive and custom project incentives, study incentives, application assistance, SEM, and energy team facilitation for customers with more than 1 MW peak demand or 100,000 therms of gas use per month and more than $60,000 of monthly energy expenses.

Strategic Energy Management

AEP Ohio, Continuous Energy Improvement (CEI), Ohio. Training, start-up grants, performance-based financial incentives, and no-cost building walkthroughs for up to three customer facilities to establish continuous improvement practices by customers with high energy use facilities.

Puget Sound Energy, Commercial Strategic Energy Management (CSEM), Washington. Technical assistance, peer teaching and reinforcement, energy modeling, and a per-kWh savings incentive for commercial and industrial customers.

Residential Comprehensive Retrofit

Eversource, Home Energy Services (HES) Program, Massachusetts. In-home energy assessments, base load, thermal boundary, and mechanical measures, financial incentives, and 0% financing for homeowners and renters in one- to four-unit homes.

Southwestern Electric Power Company (SWEPCO), Home Performance with ENERGY STAR (HPwES), Arkansas. No-cost Home Performance with ENERGY STAR (HPwES), with participation eligibility based on the inefficiency of the home.

New Hampshire Utilities, NHSaves Home Performance with ENERGY STAR (HPwES) Program, New Hampshire. Low-cost energy audits, incentives, and low-interest financing support a whole-home approach delivered through a network of 20 local weatherization contractors.

Oklahoma Gas and Electric (OG&E) and Arkansas Oklahoma Gas Corporation (AOG), Joint Weatherization Program, Arkansas. Energy audits and incentives for residential gas and electric efficiency measures, prioritized by cost effectiveness.

Residential Miscellaneous

Efficiency Vermont, Heat Pump Water Heaters, Vermont. Retail and online prescriptive rebates for customers, combined with midstream incentives for wholesalers and distributors, for certified advanced and high-efficiency water heaters.

Entergy Arkansas, Energy Solutions for Manufactured Homes, Arkansas. Audits and direct-install measures for manufactured homeowners and residents.

CenterPoint Energy and Xcel Energy, Home Energy Squad (HES), Minnesota. Energy audits, direct-install measures, and coordination with insulation contractors for residential customers.

Multifamily

BayREN, Bay Area Multifamily Building Enhancements (BAMBE), California. Whole-building retrofit program offering no-cost energy consulting and cash rebates to multifamily customers in the San Francisco Bay Area.

Eversource, Multifamily Initiative, Connecticut. Energy assessment, technical assistance, incentives, and financing for energy efficiency upgrades to multifamily buildings.

Puget Sound Energy, Multifamily Retrofit and New Construction for Market Rate and Low Income, Washington. Free walk-through site assessment, no-cost direct-install measures, portfolio benchmarking, trade ally network, and prescriptive and calculated incentives for electric and gas measures.

PSE&G, Residential Multifamily Housing Program, New Jersey. Multifamily housing retrofits including upfront engineering and construction funding, incentives, and on-bill financing.

Low-Income: Statewide Comprehensive

Efficiency Vermont, Low-Income Electric Efficiency Program (LEEP), Vermont. Contracts with the state's Weatherization Assistance Program (WAP) agencies to install electrical efficiency measures in income-eligible single- and multifamily homes; Targeted High Use Program provides no-cost energy coaching, energy assessment, and efficient product and HVAC upgrades.

New York State Energy Research and Development Authority (NYSERDA), EmPower New York, New York. Comprehensive energy efficiency program providing no-cost electric reduction and home performance measures to low-income households.

Massachusetts Utilities, Low-Income Energy Affordability Network (LEAN), Massachusetts. No-cost comprehensive weatherization, appliance efficiency, and heating system measures and services to eligible low-income households for all fuels (electricity, gas, oil, propane).

NHSaves, Home Energy Assistance Program (HEA), New Hampshire. Whole-house approach from energy audit through installation and inspection, implemented with Community Action Agencies (CAAs) and additional collaboration with state and federal WAP.

Low-Income: Natural Gas Utilities

Columbia Gas of Ohio, WarmChoice, Ohio. No-cost energy efficiency services to income-qualified households targeting high natural gas usage households and those with high arrearages.

Oklahoma Natural Gas, Low-Income Energy Efficiency Assistance Program, Oklahoma. No-cost attic insulation, air sealing, and duct sealing, including evaluation and installation, available to all income-qualified residential customers.

Low-Income: Targeted/Social Equity

Maryland Energy Administration (MEA), EmPOWER Clean Energy Communities Low-to--Moderate-Income (LMI) Grant Program, Maryland. Grants to nonprofits and local governments for whole-building, new construction, and individual measure energy efficiency upgrades that benefit low- to moderate-income Marylanders.

Xcel Energy, Low-Income, Colorado. Single-family weatherization through WAP and Colorado Affordable Residential Energy (CARE), income-qualified multifamily, and the Nonprofit Energy Efficiency Program (NEEP) for nonprofit organizations serving income-qualified communities.

New Construction

AEP Ohio, EfficiencyCrafted Homes, Ohio. Above-code energy performance through technical standards, training, and cost-effective incentives for builders, combined with consumer education and marketing, and a pay-for-performance incentive structure.

Energy Trust of Oregon, EPS New Construction, Oregon. New home construction program uses EPS, an energy performance scoring system providing performance-based scaled incentives to builders and third-party raters for installing energy improvements beyond state energy codes.

Xcel Energy, Energy Design Assistance, Colorado. Helps building design teams include energy savings before construction begins by using computer simulation modeling to forecast the planned building's energy performance, and then suggests energy-saving strategies and projects energy-cost savings.

New Construction: Path to Net Zero

Efficiency Vermont, High-Performance Homes Program, Vermont. Net zero ready, prescriptive-incentive program for residential new construction customers seeking stick-built homes; Zero Energy Modular (ZEM) Homes pathway for LMI customers; technical assistance from planning phase through construction at no cost to the customer.

Energy Trust of Oregon, New Buildings: Path to Net Zero, Oregon. Design-based initiative using energy use intensity (EUI) targets to set 70% energy reduction compared to typical building goals.

Heating, Ventilating, and Air-Conditioning (HVAC)

Efficiency Maine Trust, Ductless Heat Pump Initiative of the Home Energy Savings Program (HESP), Maine. Drives market toward high-efficiency ductless heat pumps through fixed-price rebates and loans, quality assurance, customer education, and marketing through qualified contract network.

Oncor Electric Delivery, Multifamily HVAC, Texas. Replacement of electric resistance heating systems with high-efficiency heat pumps using marketing targeted to property management companies, HVAC companies, and multifamily contractors.

Toronto Hydro-Electric System Ltd., PUMPsaver Local Program, Ontario. Direct installation of variable frequency drives on hydronic distribution systems for multiunit residential building facilities and customers in other sectors.

Lighting

Commonwealth Edison, LED Street Lighting, Illinois. Retrofits of municipal- and/or utility-owned high-intensity discharge (HID) streetlights to LED.

Consumers Energy, Advanced Lighting Controls (ALC), Large Business, Michigan. Technical training and tiered per-kWh incentives for fully networked lighting systems that leverage multiple control strategies for business and institutional customers.

Focus on Energy, Retail Lighting and Appliance, Wisconsin. Upstream incentives for ENERGY-STAR-certified LED lightbulbs at retail locations, smart thermostat rebate, online appliance marketplace for consumer research, and participation in the ENERGY STAR® Retail Products Platform (ESRPP) pilot.

Pacific Gas and Electric (PG&E), LED Accelerator Program (LEDA), California. Custom retrofits and new construction, tiered incentives for retail, downstream, and pay-for-performance for best-in-class LEDs and networked lighting controls (NLCs).

On-Bill Lending

Ouachita Electric Cooperative, HELP PAYS®, Arkansas. Tariffed on-bill (TOB) financing program that reduces the upfront costs of energy efficiency upgrades for residential, municipal, and nonprofit member-owners of the co-op.

AVANGRID, Small Business Energy Advantage, Connecticut. Turnkey energy efficiency services and financial incentives for small commercial customers, combined with 0% financing and on-bill repayment to provide positive cash flow.

Agriculture

Entergy Arkansas, Agricultural Energy Solutions, Arkansas. Farm audits, prescriptive and custom incentives, and education for farmers, agribusiness, and agricultural equipment suppliers.

Consumers Energy, Agriculture Energy Efficiency, Michigan. Prescriptive rebates for 43 electric and gas technology measures, custom projects, and rebates for US Department of Agriculture (USDA) Tier 2 audits.

Utility Partnerships

PG&E, California Youth Energy Services, California. Training and employment of local young adults to provide free energy efficiency and water conservation services including home assessment, installations, education and behavior change, and referrals.

Los Angeles Department of Water and Power and SoCalGas, Master Inter-Utility Agreement, California. Partnership structure for the coordination and integration of multiple inter-utility efficiency programs.

Irvine Ranch Water District (IRWD), Southern California Edison (SCE), and SoCalGas, One-Stop Shop for Water and Energy Efficiency, California. A water–energy nexus direct-install program for mutual customers in the IRWD service area.

Xcel Energy, Partners in Energy, Colorado and Minnesota. Collaboration and utility support to develop community-driven energy action plans and implementation support including marketing, project management, tracking, reporting, funding for incremental staffing or events, online webinars, office hours, and in-person education and networking forums.

Niche

CenterPoint Energy, Foodservice, Minnesota. Provides energy efficiency rebates and the company's Foodservice Learning Center to commercial, large-volume cooking customers, and foodservice trade allies.

Eversource, Franchise Customer Initiative, Massachusetts. Technical services at the retail site including studies of energy cost and savings impacts, implementation guidance, and project-level incentives for franchise businesses.

MassSave, C&I Natural Gas Water Heater Initiative, Massachusetts. Upstream rebates and cash incentives to distributors for the sale of high-efficiency water heater equipment to commercial- or industrial-rate natural gas customers.

NV Energy, Residential Demand Response, Nevada. Free smart thermostats, energy efficiency service subscriptions, and annual rebates for residential customers who agree to participate in demand response events.

PSE&G, Hospital Energy Efficiency Program, New Jersey. Incentives, upfront payments, and on-bill financing of energy conservation measures at hospitals and healthcare facilities operating 24/7.

Commonwealth Edison, ComEd Energy Efficiency Program Retro-Commissioning (RCx) Offering, Illinois. Four RCx program options that include no-cost engineering studies to identify no- and low-cost operational improvements for existing energy-using systems in businesses and public facilities.

Background

ACEEE has reviewed utility-funded energy efficiency programs nationwide every five years since 2003 to identify trends and present effective approaches. The authors of the first review recognized the extent to which programs had evolved since the 1970s and seized the opportunity to document the state of practice for successful programs. By presenting models of excellence in multiple customer sectors and business segments, the 2003 report addressed a previously unmet need (York and Kushler 2003).

The industry responded favorably to that first review, leading ACEEE to repeat and refresh the process with *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008). That report profiled 90 programs selected as models for other utilities to learn from. ACEEE followed up again five years later, releasing *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs* (Nowak et al. 2013).

Utility-sector energy efficiency programs are more important than ever. Energy efficiency continues to be one of the cleanest and lowest-cost utility system resources (Lazard 2017; Hoffman, Leventis, and Goldman 2017). Utilities have expanded their energy efficiency portfolios, generating increasing cumulative energy savings impacts. Figure 1 shows the increase in total electric savings from ratepayer-funded electric programs.

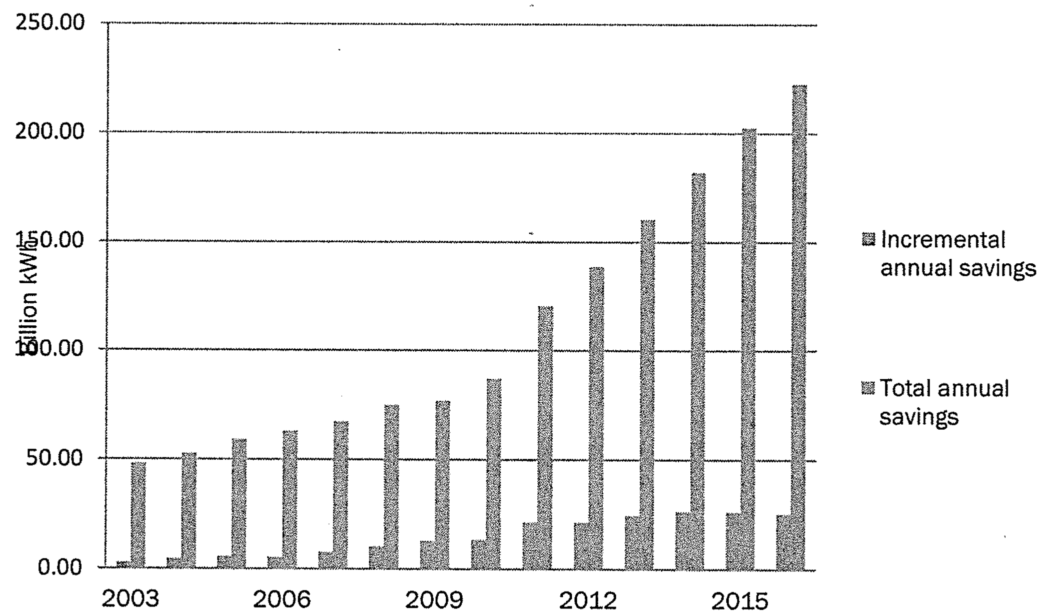

Figure 1. Total annual electricity savings from utility ratepayer-funded programs, 2003–2016. Total annual savings numbers reflect savings for previously installed measures that continue to deliver savings in the year shown. *Source:* Berg et al. 2017.

When ACEEE published its first national review of exemplary programs in 2003, US gas and electric utilities were spending $1.4 billion per year on energy efficiency. As figure 2 shows, utilities now invest more than five times that amount, over $7 billion annually, and have maintained that level every year since 2014 (Berg et al. 2017).

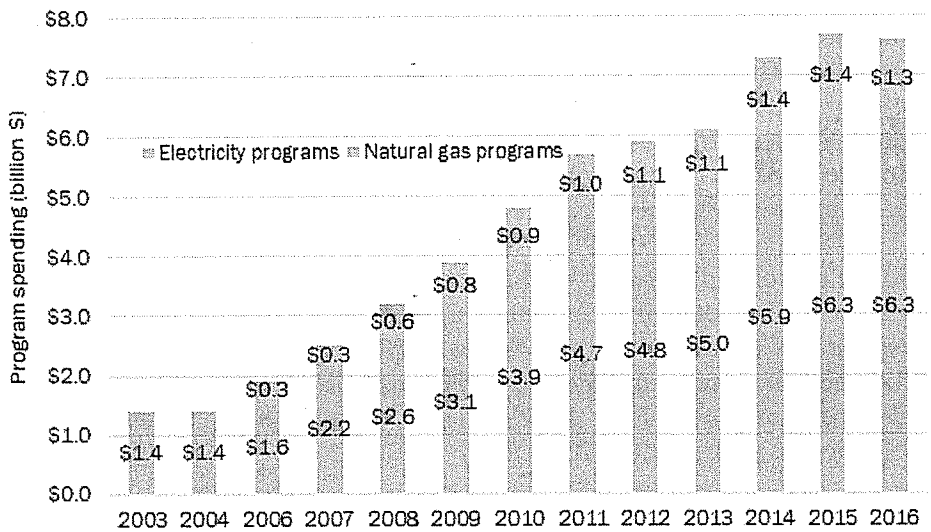

Figure 2. Annual electric and natural gas energy efficiency program spending. Natural gas spending is not available for 2003 and 2004. *Source:* Berg et al. 2017.

While the need for innovation and adaptation has remained constant across the ACEEE reviews timeframe, program administrators face a constantly evolving set of challenges to administering successful energy efficiency programs. Recent developments include the tightening of many building codes and lighting and appliance standards, concern that utilities have already harvested much of the low-hanging fruit, and the widespread adoption of technological advancements such as advanced metering and smart technologies.[2] Those factors all contributed to our decision to conduct a new exemplary programs review in 2018.

Report Purpose

In this fourth ACEEE national review of exemplary energy efficiency programs, we present profiles of 53 high-performing programs in 14 customer sector and end-use categories. This review serves two objectives: to identify and promulgate successful approaches that might help others improve their program designs, and to recognize utilities and other administrators that are funding and delivering excellent programs.

We examine leading efforts in residential, commercial, and industrial customer sectors to facilitate the borrowing and adapting of strategies across sectors, end uses, and

[2] We would note that in the energy efficiency context, there is not a fixed or static amount of low-hanging fruit. Due to continuing improvements in technology and reductions in cost, new forms of low-hanging fruit tend to appear over time. Nevertheless, there is some concern in the industry that program administrators may have harvested the easiest-to-capture efficiency improvements first.

technologies.[3] Disseminating examples of effective designs is increasingly important in today's industry environment. The need for improvement is growing, driven by factors such as regulatory requirements to meet aggressive energy savings targets in the context of increasingly fast-changing markets—both as codes and standards are adopted for existing technology and as new technology and new market opportunities emerge. This report facilitates peer learning to meet that demand.

The exemplary awards also give well-earned credit to the people and organizations who contribute to the industry year after year. ACEEE exemplary program reports have been prominent and popular, and the 2013 *Leaders of the Pack* was among the most-downloaded ACEEE research reports that year. These reports offer a set of models or prototypes for illustrative purposes only; we do not claim that these are the nation's best programs. No doubt other excellent programs exist that were not part of our review and selection process. Attempting to assess all US programs would be neither feasible nor necessary to meet our project's purpose, which is to identify exemplary programs worthy of emulation.

Methodology

The methodology we used for this *Fourth National Review* is consistent with predecessor reports. We issued a broad call for nominations of exemplary programs from people and organizations across the industry, reviewed the pool of nominations with the help of an expert panel, and selected the winners by considering program features and performance as well as expert opinions. Unlike the open nomination process of previous years, ACEEE required that this year's nominations be within predetermined program categories as described below.

SCOPE

Consistent with past practice, to be eligible for consideration, we required nominated programs to be

- Located in the United States or Canada
- Funded, at least in part, through utility rates, public benefits charges, or similar utility revenue mechanisms
- Administered by utilities, government agencies, or third-party independent administrators
- Electric, natural gas, or dual-fuel, or a combination
- One of no more than three nominations submitted from their own portfolio by a utility or program administrator from a particular state

SELECTION CRITERIA

When deciding whether to recognize a nominated program as exemplary, we considered the following factors:

[3] ACEEE also performs extensive research on exemplary programs and best practices in specific program categories. These focused research reports go into more depth on market transformation and on multifamily, low-income, small business, smart building, and other programs.

- *Direct energy savings.* Does the program deliver substantial immediate and long-term kWh (and/or therm) savings from energy efficiency?
- *Cost effectiveness.* Does the program yield significant energy savings and related benefits relative to its costs?
- *Market impacts.* Does the program produce desirable and lasting improvements in the energy efficiency characteristics and performance of the targeted market?
- *Customer service.* Does the program provide high-quality service and achieve high levels of customer satisfaction?
- *Innovation.* Does the program incorporate particularly innovative measures, program designs, and/or implementation techniques that have achieved positive near-term results and promise significant future impacts?
- *Transferability, replicability, and expansion potential.* Is the program design easily replicable in other, similar settings?

Initial Program Categories

For this 2018 effort, we limited nominations to a predetermined set of categories. To highlight an array of successful approaches, we invited nominations in 15 areas. These represented widely diverse programs that varied by fuel, customer sector, industry segment, end use, technology, and other characteristics. We selected a category based on multiple characteristics, including the area's growth potential, whether it historically accounted for deep and lasting energy savings, and whether it represented new or different institutional arrangements. We also added categories to capture exemplary programs worthy of emulation that did not fit elsewhere, including residential miscellaneous, and medium and large commercial and industrial programs. We did not include behavior programs among the categories, since over the past few years ACEEE has dedicated several reports to recognizing exemplary programs of this type (Sussman and Chikumbo 2016; Grossberg et al. 2015; Mazur-Stommen and Farley 2013).

The initial program categories were

- Small commercial (could include targeted small business subsectors, e.g., restaurants and convenience stores)
- Medium and large commercial or industrial
- Strategic energy management (SEM) (any sector)
- Residential comprehensive retrofit
- Residential miscellaneous (other than lighting, HVAC, or shell; could include water heating, plug loads, or appliances)
- Multifamily
- Residential low income or income eligible
- Ultra-low energy new construction homes and buildings (any sector)
- Residential or commercial HVAC (heating and/or cooling)
- Lighting (any sector; must demonstrate past performance and have potential for the future)
- On-bill lending (any sector)

- Agriculture (programs or initiatives targeted and designed for agriculture sector customer energy efficiency needs and end uses)
- Utility-city partnerships or community strategies (any sector)
- Combined energy efficiency and demand response; integrated demand side management (DSM) (must have a strong energy efficiency component)
- Geotargeted energy efficiency programs (any sector)

SOLICITATION OF PROGRAM NOMINATIONS

We designed the exemplary review methodology to attract program nominations from people in the industry. We did not begin the process with data collection on all utility energy efficiency programs; instead, we limited the pool of nominations to those submitted by people who were aware of the process and who invested the time to complete nomination forms. This made it important to publicize the review widely. To do so, we leveraged the extensive ACEEE database and network of energy efficiency contacts. We primarily relied on a series of mass email messages and reminders targeted to reach program administrators, implementation contractors, regional energy efficiency organizations, and regulators. We also solicited nominations through the ACEEE website, staff members' professional contacts, and social media. Regional energy efficiency organizations placed notifications on their websites and featured the call for nominations in online newsletters.

Representatives from across the industry responded resoundingly to the call, nominating a diverse collection of 112 gas and electric energy efficiency programs representing every eligible category.

The pool of nominations represented every type of program administrator, including federal power authorities, municipal utilities, investor-owned utilities, state agencies, nonprofit organizations, regional energy efficiency organizations, third-party program administrators, and rural electric cooperatives. The set of nominated programs was more geographically diverse than in the past, representing 39 states and 3 Canadian provinces, compared with 36 states in 2013, and 23 states in 2008.

We received an average of eight nominations per category, excluding geo-targeted programs, which had only one. We eliminated one category—combined energy efficiency and demand response (integrated DSM)—because the five nominations submitted were primarily smart thermostat programs that our staff and advisory panel did not select as exemplary models of integrated DSM.

PROCESS OF PROGRAM REVIEW AND SELECTION OF WINNERS

To review and assess the nominated programs, we relied on both the selection criteria and the knowledge and experience of internal and external experts.

Internally, at least four of us—including a subject matter expert for the program category—assessed each nominated program. We reviewed each program's design and strategy, examining the customer sectors, marketing, measures, services, incentives, and quantitative performance data. We then looked at evaluation reports where available. We made notes and recorded overall ratings of every nominated program in a central database.

In parallel with our internal reviews, we convened a review panel of three outside energy efficiency experts, each of whom was tasked with reviewing a specific set of program categories. At least two of the experts reviewed each submission, assessing overall quality and taking into consideration the six primary selection criteria and other factors.

To select winners, we used a consensus-building process in discussions with the expert panel members. We first considered programs with the highest overall ratings in each program category as potential winners, using quantitative performance data and expert judgments and opinions to select a set for each category. However we did not select winners based on quantitative ranking alone; we often recognized programs because they were good examples of particular strategies or designs. Our objective was to identify a representative set of exemplary programs in each program category.

FINAL PROGRAM CATEGORIES

After reviewing the many high-quality submissions, we refined the program categories in two ways.

First, we added an additional category for exemplary niche programs. These demonstrate strong performance by tailoring energy efficiency offerings to specific targeted market niches such as specific industry sectors (foodservice and hospitals), type of businesses (franchise retailer), technology (smart thermostats), end use (commercial and industrial water heating), and building systems (retrocommissioning).

Second, we subdivided two of the initial categories to distinguish important characteristics. Of the 18 low-income program nominations, we recognized two administered by natural gas utilities and four comprehensive statewide programs. We also created a third group for innovative and noteworthy equity elements that could be adapted elsewhere, such as providing energy efficiency services to nonprofit organizations that serve low-income communities. For new construction, we distinguished between programs that aim at net zero buildings and other exemplary offerings.

We also eliminated two categories (combined energy efficiency and demand response/integrated DSM, and geotargeted programs) for which we received few strong nominations.

In the past, in addition to honoring Exemplary Programs, ACEEE conferred honorable mention awards to innovative programs that showed promise for the future but lacked a demonstrated performance history. This year we received multiple high-quality nominations in almost every category; in part because of this, we decided not to confer honorable mention recognition.

Results

As in prior years, we analyzed and selected programs to profile. This time we reduced the number of profiles and their length in order to make key attributes more accessible to readers. After examining the pool of nominations by category, we selected 53 exemplary programs.

One should not generalize or draw conclusions about the utility energy industry as a whole by extrapolating from our selections. We have highlighted a few relevant and illustrative models in each program category. Utilities face various challenges depending on the program type, and they have developed a variety of models to meet those challenges. Successful strategies and approaches are often specific to end use, customer sector or subsector, or technology.

For example, lighting programs have evolved over the years, in part in response to the advance of federal standards that reduce the savings that utilities may claim from each measure. Although many relatively simple prescriptive rebate programs established years ago have continued, they have changed in many ways. The compact fluorescent lamp (CFL), for example, has declined as a program mainstay as light-emitting diodes (LEDs) have gained market share. The set we recognize here shows the diversity in the lighting area, including programs featuring LEDs, distribution channel, advanced controls, and streetlights.

Table 1 presents our roster of 53 exemplary programs serving 23 states and 1 Canadian province.

Table 1. Exemplary programs

Category	Program	Utility or program administrator	State
Small commercial	ComEd® Energy Efficiency Program Small Business Offering	Commonwealth Edison (ComEd)	IL
	Small Business Energy Efficiency Solutions	Consumers Energy	MI
	Direct Install	New Jersey Board of Public Utilities, Office of Clean Energy	NJ
	One-Stop Efficiency Shop	Xcel Energy	MN
	Small Business Energy Advantage[a]	AVANGRID	CT
Medium and large commercial and industrial	Energy Smart Industrial (ESI)	BPA	OR, WA, ID, MT, NV, CA, WY
	Large Energy Users Program	Focus on Energy/APTIM	WI
Strategic energy management	Continuous Energy Improvement (CEI)	AEP Ohio	OH
	Commercial Strategic Energy Management (CSEM)	Puget Sound Energy	WA

Category	Program	Utility or program administrator	State
Residential comprehensive retrofit	Home Energy Services (HES)	Eversource	MA
	Home Performance with ENERGY STAR® (HPwES)	Southwestern Electric Power Company (SWEPCO)	AR
	NHSaves Home Performance with ENERGY STAR (HPwES) Program	NH Utilities[b]	NH
	OG&E/AOG Joint Weatherization Program	Oklahoma Gas and Electric Co. (OG&E) and Arkansas Oklahoma Gas Corporation (AOG)	AR
Residential miscellaneous	Heat Pump Water Heaters	Efficiency Vermont	VT
	Energy Solutions Manufactured Homes Program	Entergy Arkansas	AR
	Home Energy Squad (HES)	CenterPoint Energy and Xcel Energy	MN
Multifamily	Bay Area Multifamily Building Enhancements (BAMBE)	BayREN	CA
	Multifamily Initiative	Eversource	CT
	Multifamily Retrofit and New Construction for Market Rate and Low Income	Puget Sound Energy	WA
	Residential Multifamily Housing Program	PSE&G	NJ
Low-income: statewide comprehensive	Low-income Electric Efficiency Program (LEEP)	Efficiency Vermont	VT
	EmPower New York	NYSERDA	NY
	Low-Income Energy Affordability Network	MA utilities	MA
	NHSaves Home Energy Assistance Program (HEA)	NH utilities and agencies	NH
Low-income: natural gas utilities	WarmChoice®	Columbia Gas of Ohio	OH
	Low-Income Energy Efficiency Assistance Program	Oklahoma Natural Gas	OK
Low-income: targeted/social equity	EmPOWER Clean Energy Communities Low-to-Moderate Income (LMI) Grant Program	Maryland Energy Administration (MEA)	MD
	Low-Income Program	Xcel Energy	CO
New construction	EfficiencyCrafted℠ Homes	AEP Ohio	OH
	EPS New Construction (New Homes)	Energy Trust of Oregon	OR
	Energy Design Assistance	Xcel Energy	CO
New construction: path to net zero	High-Performance Homes	Efficiency Vermont	VT
	New Buildings: Path to Net Zero	Energy Trust of Oregon	OR

Category	Program	Utility or program administrator	State
HVAC	Ductless Heat Pump Initiative of the Home Energy Savings Program (HESP)	Efficiency Maine Trust	ME
	Multifamily HVAC Program	Oncor Electric Delivery	TX
	PUMPsaver Local Program	Toronto Hydro-Electric System Limited	ONT
Lighting	LED Street Lighting Program	Commonwealth Edison (ComEd)	IL
	Advanced Lighting Controls (ALC), Large Business	Consumers Energy	MI
	Retail Lighting and Appliance	Focus on Energy	WI
	LED Accelerator Program (LEDA)	Pacific Gas and Electric (PG&E)	CA
On-bill lending	HELP PAYS®	Ouachita Electric Co-op	AR
	Small Business Energy Advantage	AVANGRID	CT
	Residential Multifamily Housing Program[c]	PSE&G	NJ
Agriculture	Agricultural Energy Solutions	Entergy Arkansas	AR
	Agriculture Energy Efficiency	Consumers Energy	MI
Utility partnerships	California Youth Energy Services	PG&E	CA
	Master Inter-Utility Agreement	SoCalGas and LADWP	CA
	One-Stop Shop for Water and Energy Efficiency	IRWD, SCE, and SoCalGas	CA
	Partners in Energy	Xcel Energy	CO, MN
Niche programs	Foodservice	CenterPoint	MN
	Franchise Customer Initiative	Eversource	MA
	MassSave C&I Natural Gas Water Heater Initiative	MassSave and its program administrators	MA
	Residential Demand Response Program	NV Energy	NV
	Hospital Efficiency Program	PSE&G	NJ
	ComEd Energy Efficiency Program Retro-Commissioning (RCx) Offering	Commonwealth Edison (ComEd)	IL

[a] Profile is in Appendix A on-bill lending section. [b] Eversource (electric); Liberty Utilities (electric and natural gas), New Hampshire Electric Cooperative (electric), Unitil Energy Systems (electric), and Northern Utilities (natural gas). [c] Profile is in Appendix A multifamily section.

EXEMPLARY PROGRAM PROFILES

Appendix A presents short descriptions of each exemplary program. The categorization and order are the same as in table 1. Each profile is included in only one program category, although a few are cross-listed in the roster if they fit into more than one category.

Our intention is to provide only a brief overview, not a comprehensive or complete description. Each profile begins with a program-at-a-glance table that includes the name and contact information of the best person to contact for further information. We encourage you to reach out. Every representative listed is not only knowledgeable but also willing to collaborate for the good of the industry.

The profiles continue with a description of exemplary features and accomplishments, lessons learned that program managers or implementers have shared to benefit peers who are starting or running similar programs. Each profile concludes with a table of performance data for the three most recent program years.

While ACEEE provided the profile format, the program administrators wrote the actual text themselves, so writing styles and terminology vary across the profiles. If you have questions or need further information about a program, please contact the designated person identified in the profile's at-a-glance table.

Observations

The utility energy efficiency field is dynamic, with changes in policies and markets leading to advancements in program design and delivery. We noticed a number of themes and trends as we reviewed the exemplary programs. One influence has been the strengthening of federal lighting efficiency standards, which has reduced the amount of energy savings utilities may claim from lighting programs. As lighting's role in portfolios becomes smaller, programs are turning to other end uses, and savings from new technologies are growing.

Another important factor has been an increase in energy savings goals associated with state energy efficiency resource standards (EERSs). Programs are increasingly tailoring their offerings to comply with EERS policies. For example, they are deploying strategic energy management (SEM) to commercial and industrial customers; designing new construction programs to achieve deeper savings than ever before, up to and including net zero homes and buildings; and directing financial incentives upstream and midstream for greater impact on efficient water heating markets. As utilities develop emerging technologies from pilots into full-scale programs, they are offering products and equipment with higher energy efficiency in every industry and sector. One-size-fits-all programs are giving way to targeted designs that support every type of customer.

Our more specific observations include the following.

Strategic energy management (SEM) programs are demonstrating success in serving commercial and industrial customers. SEM establishes a commitment and internal structure within the customer's organization to identify and pursue energy efficiency improvements. AEP Ohio's Continuous Energy Improvement program and Puget Sound Energy's Commercial Strategic Energy Management program exemplify this approach.

Multifamily programs are proliferating and diversifying. ACEEE has previously documented the growth of multifamily programs, finding new ones in 22 of 51 metropolitan areas studied between 2011 and 2015 (Samarripas, York, and Ross 2017). Our report profiles several successful, cost-effective models providing both gas and electric measures, with services including no-cost consulting, energy assessments, whole-building retrofits, direct-install measures, engineering and construction funding, and on-bill financing. Exemplary multifamily programs serve both market-rate and income-eligible customers.

Low-income programs reaching customers with high energy burdens are growing in importance. Energy burden is the percentage of household income that goes toward energy expenses (Drehobl and Ross 2016; Ross, Drehobl, and Stickles 2018). We received 19 low-income program nominations, more than in any other category, and, due to their strength, we recognized 8 of them. They include statewide comprehensive models, natural gas utility offerings, and programs that work with nonprofit organizations and local governments to serve low-income residents. Seven of the eight profiled programs have increased their spending over the past three years.

Lighting programs are deploying new designs and strategies. Traditional lighting programs that provide rebates to customers at the retail level are becoming less prominent. Programs are shifting to provide advanced lighting technologies through midstream and upstream delivery channels. They are also increasingly focusing on systems like networked lighting controls rather than on lamps and fixtures (King and Perry 2017). LED street lighting for municipal and utility customers is another noteworthy program category.

New construction programs are embarking on a path to net zero energy. A number of exemplary programs support the construction of ultra-low-energy buildings in both the commercial and residential sectors. Efficiency Vermont's High-Performance Homes program includes both net zero-ready options and a pathway to net zero modular homes for low- and moderate-income customers. Energy Trust of Oregon's Commercial New Buildings Path to Net Zero aims at reductions in energy use intensity of 70% relative to typical building goals.

Leading upstream- and midstream-focused programs leverage rebates in product distribution channels for greater market impact. For example, Efficiency Vermont's Heat Pump Water Heaters program provides rebates at retail, online, wholesale, and distributor levels, achieving market penetration of more than 29 times the national average on electric-to-electric conversions. The Mass Save C&I Natural Gas Water Heater Initiative provides financial incentives to distributors to maintain high-efficiency inventory, offer price discounts to customers, and educate the market. The initiative achieves more than 20 times the savings of equivalent customer mail-in rebate programs.

Utilities are partnering with a number of other entities. Collaborative program models include gas and electric utility partnerships, coordinated energy and water conservation, and work with local government entities and nonprofit organizations. Nonprofit Rising Sun Energy Center implements California Youth Energy Services (CYES) for PG&E. CYES engages with and is funded by cities, counties, water districts, nonprofit organizations, and a private foundation. In another program, SoCalGas and the Los Angeles Department of Water and Power have formed a partnership for rebate programs, direct install, outreach, and R&D coordination and delivery.

Programs increasingly target particular industry segments, customer subsectors, and technologies instead of relying on a one-size-fits-all design. We recognize a diverse set of six niche programs to illustrate programs tailored to specific market segments. For example, the PSE&G

Hospital Energy Efficiency program serves only a handful of large institutions a year with large capital-intensive projects that address the unique needs of healthcare facilities. The CenterPoint Energy Minnesota Foodservice program provides rebates and training each year to hundreds of trade allies and commercial, large-volume customers.

Conclusions

Electric and natural gas utility energy efficiency programs continue to deliver value in every customer segment year after year. Energy savings continue to grow, with resulting benefits for household and business cost savings, the environment, and the economy.

As policymakers increase energy savings targets and adopt more-stringent codes and standards over time, program developers and designers continue to innovate. Today's leading program implementers have been building on and incorporating utility industry lessons for more than 30 years. They have enhanced program approaches and marketing and introduced new generations of high-efficiency products and technologies while maintaining cost effectiveness and increasing savings.

This fourth national review of exemplary energy efficiency programs, like the first three, is an up-to-date resource for anyone interested in improving or expanding utility-sector energy efficiency programs. The exemplary programs profiled in this report include replicable models for success that can be adapted to suit most states and regions and various customer types and market sectors.

The professionals behind each of these exemplary programs have proven their commitment to serving customers, and their success shows in their performance results. We congratulate the individuals and organizations responsible for the programs selected, and we hope that the information here will be useful to others in the industry.

EXHIBIT TW/EM – 27

ACEEE ENERGY EFFICIENCY RESOURCE STANDARDS

Energy Efficiency Resource Standards

An energy efficiency resource standard (EERS) is a quantitative, long-term energy savings target for utilities. Under direction from this policy, utilities must procure a percentage of their future electricity and natural gas needs using energy efficiency measures, typically equal to a specific percentage of their load or projected load growth. Energy savings are typically achieved through customer, end-use efficiency programs run by utilities or third-party program operators, sometimes with the flexibility to achieve the target through a market-based trading system.

Alabama

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: June 2017

Alaska

In June 2010, Governor Sean Parnell signed House Bill 306 into law. The legislation established Alaska's state energy policy, which included an aggressive renewable electricity goal, as well as a goal to reduce per capita electricity use in the state by 15% by 2020. This goal must be translated into specific requirements for utilities to achieve savings of a specific amount to qualify as an EERS.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: June 2016

Arizona

Summary: Cumulative annual electricity savings of 22% of retail sales and natural gas savings of 6% by 2020.

In 2010 the Arizona Corporation Commission ordered that, by 2020, each investor-owned utility must achieve cumulative annual electricity savings of at least 22% of its retail electric sales in calendar year 2019 through cost-effective energy efficiency programs (see Docket No. RE-00000C-09-0427, Decision No. 71436, and Decision No. 71819). Cumulative annual targets for electricity savings are specified for each year, beginning at 1.25% in 2011, and are based on retail electricity sales in the previous calendar year. Electric distribution cooperatives must propose an annual energy savings goal that is at least 75% of the standard in a given year.

Peak demand savings achieved through demand response programs are allowed to qualify for up to two percentage points of the total 22% cumulative goal (based on a conversion of demand to energy), but there is a limit to the amount of peak demand savings that can be applied to the energy efficiency standard in any given year. Utilities can count energy supply from combined heat and power systems that do not qualify under the state's Renewable Energy Standards towards the energy efficiency standard, as well as one-third of the measured savings from new building codes. Utilities are allowed to credit energy savings achieved during 2005-2010 towards the requirements beginning in 2016.

Utilities must submit an annual or biennial implementation plan to detail progress in meeting goals and to estimate cost and energy savings for programs over the next two calendar years. Utilities may recover the prudent costs of energy efficiency programs through a DSM tariff, and utilities may also request the Commission to consider the use of performance incentives to assist in achieving the goals.

Arizona also has natural gas efficiency standards requiring 6% cumulative savings by 2020 (see Docket No. RG-00000B-09-0428 and Decision No. 71855). As in the case of electric cooperatives, gas cooperatives must propose annual savings goals that achieve 75% of the standard; propane companies must meet 50% of the standard. Energy savings from renewable energy projects sponsored by an affected utility may count towards meeting up to 25% of the standard in any given year.

Salt River Project has also set long-term energy savings goals through its Sustainable Portfolio Principles. These principles establish targets for the utility through its 2020 fiscal year and ramp up to 2% beginning in FY 2018.

Last Updated: July 2016

Arkansas

Summary: For 2020-2022, savings targets are 1.20% of 2018 baseline sales for electric utilities, and 0.5% of baseline sales for natural gas utilities. Incremental savings targets were 0.9% annually for 2015-2018, and 1.0% for 2019, with yearly incremental natural gas savings of 0.5% for 2017-2019.

In 2018 the PSC ordered higher incremental savings targets in Docket No. 13-002-U, Order No. 43. For program years 2020-2022, the utilities are now required to hit savings targets 1.20% of 2018 baseline sales for electric utilities and 0.50% of 20l8 baseline sales for natural gas utilities.

In December 2010, Arkansas PSC adopted an energy efficiency resource standard (see Docket No. 08-144-U). The targets set by the Public Service Commission were moderate, rising from a yearly reduction of 0.25% of total electric kilowatt hour (kWh) sales in 2011, to 0.5% in 2012, and 0.75% in 2013. Natural gas targets were set at 0.2% in 2011, 0.3% in 2012, and 0.4% in 2013.

In January 2013, the Public Service Commission issued an order in Docket 13-002-U seeking comment on proposed savings goals for the next three-year program cycle. The proposed goals by the PSC staff would double the previous yearly electricity savings levels to 1% of sales in the first program year, 1.25% in the second, and 1.5% in the third. Proposed savings targets for natural gas would more than double the previous targets: 0.6%, 0.8%, and 1% per year. Based on stakeholder feedback, the PSC rescheduled the filing date to June 1, 2014, for the next three-year program cycle, and pushed back the start year so that the new program cycle is 2015-2017. For 2014, the PSC directed program administrators to use the energy savings targets, budgets, and the incentive structure previously approved for Program Year 2013 (unless program administrators seek to make modifications to program plans for approval by the PSC). In September 2013, the PSC issued an order setting an electricity savings target of 0.9% and a natural gas savings target of 0.6% for 2015. These targets were extended through 2016.

In December 2015, the PSC issued an order extending the 0.9% electricity savings target through 2018, ramping up to 1.0% in 2019, with a natural gas savings target of 0.5% for 2017-2019.

Last Updated: July 2018

California

Summary: Electric: Long-term goals average about 1.15% of retail sales electricity through 2024. Natural Gas: Incremental savings target of 0.56% through 2024.

Following California's 2001 electricity crisis, the main state resource agencies worked together along with the state's utilities and other key stakeholders and developed the California Integrated Energy Policy Report that included energy savings goals for the state's IOUs. The CPUC formalized the goals in Decision 04-09-060 in September 2004. The goals called for electricity use reductions in 2013 of 23 billion kWh and peak demand reductions of 4.9 million kW from programs operated over the 2004–2013 period. The natural gas goals were set at 67 MMTh per year by 2013.

The California Legislature emphasized the importance of energy efficiency and established broad goals with the enactment of Assembly Bill 2021 of 2006. The bill requires the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other interested parties to develop efficiency savings and demand reduction targets for the next 10 years. Having already developed interim efficiency goals for each of the IOUs from 2004 through 2013, the CPUC developed new electric and natural gas goals in 2008 for years 2012 through 2020, which call for 16,300 GWh of gross electric savings over the 9-year period (see CPUC Decision 08-07-047). See Decision 09-09-04 for 2010-2012 energy efficiency portfolios and Decision 14-10-046 for 2015 goals.

California's current targets are embedded in the approved 2016-2024 program portfolios and budgets for the state's IOUs, which calls for incremental electricity savings of about 1.15% (see CPUC Decision 15-10-028)

In 2015, California essentially doubled its energy efficiency goals by passing SB 350. This bill requires the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The bill would require the PUC to establish efficiency targets for electrical and gas corporations consistent with this goal. It would also require local publicly-owned electric utilities to establish annual targets for energy efficiency savings and demand reduction consistent with this goal. The CEC's SB 350 energy efficiency target-setting efforts are anticipated to be completed in late 2017. In May 2016, the CPUC reported initial estimates of the impact of SB350, available here.

Additional efforts that will impact savings levels include recent all-source procurement RFOs that took place in Southern California. These resulted in 145 MW of procurement and are expected to come online between 2016 and 2022. The recent Diablo Canyon Power Plant retirement proposal includes replacement of some of the energy with energy efficiency. The first phase of this, if approved, would be for 2,000 GWh of savings that commence in the years 2019-2024.

Last Updated: June 2017

Colorado

Summary: Electric: PSCo savings targets of 0.8% of sales in 2011, increasing to 1.35% of sales in 2015, after which time a flat goal of 400 GWh per year is in place through 2020. Black Hills follows PSCo targets. Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue). HB 1227, signed in June 2017, extends electric efficiency programs to 2028 and requires the commission to set goals of at least 5% peak demand reduction and 5% energy savings by 2028 for demand-side management programs implemented during 2019 through 2028 when compared to 2018 numbers.

The Colorado legislature passed HB-07-1037 in April 2007, which amended Colorado statutes C.R.S. 40-1-102 and 40-3.2-101-105 by requiring the Colorado Public Utilities Commission (COPUC) to establish energy savings goals for investor-owned electric and gas utilities. The EERS statute does not set a fixed schedule of statewide percentages of energy savings to be achieved by particular years, nor does it require the acquisition of all cost-effective energy efficiency resources. Instead, it sets an overall multi-year statewide goal for investor-owned electric utilities of at least five percent of the utility's retail sales in the base year (2006) to be met by the end of 2018, counting savings in 2018 and including savings from DSM measures installed starting in 2006. The statute includes a similar goal for reduction of peak demand of 5% of the retail system peak in 2006. For gas utilities, the statute required the PUC to open a new proceeding to develop gas savings targets and spending levels. The law empowers the PUC to set interim goals for utilities and to modify goals.

COPUC has modified targets several times since 2008 (see Docket No. 07A-420E, Decision C08-0560, Docket No. 08A-518E, Decision No. R09-0542). In May 2011, COPUC approved new goals for Public Service Company of Colorado (PSCo) for the 2012-2020 period. The goals begin at 1.14% of sales in 2012, ramping up to 1.35% in 2015, and reaching 1.68% in 2020. The goals set out to achieve 3,984 GWh in the nine-year period (see Docket No. 10A-554EG, Decision No. C11-0442). The Commission ruled in Proceeding No. 17A-0462EG that PSCo's goal for annual energy savings for 2019-2023 be 500 GWh, an increase from the goal of 400 GWh that had been in effect.Black Hills Energy’s adopted efficiency plan follows PSCo targets. In 2013, the Colorado PUC began a process to revisit certain aspects of the goals and incentive mechanisms for PSCo in Docket 13A-0686EG. It laid out a flat annual savings target of 400 GWh through 2020 in Decision No. C14-0731.

For investor-owned natural gas utilities, the EERS legislation structured the requirement in two parts. First, the natural gas IOUs must set DSM spending targets of more than 0.5% of revenues from customers in the prior year. Energy savings targets are then established by COPUC commensurate with spending and are stated in terms of quantity of gas saved per dollar of efficiency program spending.

HB 1227, signed in June 2017, extends electric efficiency programs to 2028 and requires the commission to set goals of at least 5% peak demand reduction and 5% energy savings by 2028 for demand-side management programs implemented during 2019 through 2028 when compared to 2018 numbers.

Last Updated: July 2018

Connecticut

Summary: Requirement for acquisition of all cost-effective efficiency resources, equivalent to yearly incremental electricity savings targets of ~1.51%, natural gas savings of 0.61% through 2018.

The state's renewable portfolio standard (RPS), established in 1998 and revised thereafter, requires that electricity providers and wholesale suppliers obtain 27% of their retail load from renewable energy and energy efficiency by 2020. Beginning in 2006, energy efficiency and combined heat and power measures were considered "Class III sources" and were required to meet a certain percentage of load. However, Public Act 13-303 revised the RPS to preclude certain conservation and load management programs from qualifying as a Class III source beginning January 2014.

The 2007 Electricity and Energy Efficiency Act (Public Act 07-242) took an important step in recognizing the value of energy efficiency by requiring utilities to achieve resource needs through "all available energy efficiency resources that are cost-effective, reliable and feasible." The Department of Public Utility Control interpreted this mandate overly restrictively, however, focusing only on capacity needs, and did not approve funding increases to achieve all cost-effective energy efficiency (Docket 10-02-07) until recently.

Public Act 11-80 (2011) created the Department of Energy and Environmental Protection (DEEP), into which was integrated the DPUC, renamed the Public Utilities Regulatory Authority (PURA). DEEP has several goals related to energy: to reduce the cost electricity in the state; to ensure the reliability and safety of the state's energy supply; to increase the use of clean energy; and to develop the state's energy economy. The Act requires DEEP to review the state's energy and capacity resource assessment every two years and to develop an integrated resources plan that identifies how best to meet projected demand for electricity and to lower the cost of electricity through a mixture of supply and demand-side measures, including energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies.

In 2013, the state passed Public Act 13-298, An Act Concerning Implementation of Connecticut's Comprehensive Energy Strategy. The Act contained provisions requiring gas and electric distribution companies to create triennial energy conservation plans and increased funding levels to the point where the state's all cost-effective mandate is achievable. In December 2013, PURA approved rate adjustments requested by utilities for implementation of their efficiency plans.

Last Updated: July 2018

Delaware

Summary: Delaware does not have a mandatory EERS. However, energy savings targets have been set by the Energy Efficiency Advisory Council (EEAC) and affected energy providers are currently working to meet these goals.

Established by SB 150, House Amendment 2 in 2014, the Delaware Energy Efficiency Advisory Council convened to establish guidance on cost-effective energy efficiency programs. The Delaware Energy Efficiency Advisory Council (EEAC) provides guidance to energy providers in developing energy efficiency, energy conservation, peak demand reduction, and emission-reducing fuel switching programs for all customer classes. The EEAC collaborates with the Public Service Commission (PSC) and Public Advocate (PA) to guide energy providers in establishing 3-year program portfolios that must be approved by the PSC or other appropriate regulatory body.

The Act set up an eleven-member stakeholder workgroup to assist in developing key regulations, assessing the feasibility and impact of pursuing the established targets, reviewing progress annually, and recommending changes to the plan as needed. In its June 2011 report, the workgroup identified several issues that undercut the effectiveness of the policy. First, the level of proposed funding (gathered through an energy efficiency charge on customer bills) made it unlikely that the state would meet the targets established in the Energy Efficiency Resource Standards Act. Second, the workgroup found that conflicting state statutes muddied the institutional structure around efficiency program implementation and accountability, making it impossible to determine which entity (utilities, the Sustainable Energy Utility, or the Public Service Commission) has accountability for EERS performance results and the development of enforcement mechanisms.

Given the lack of final implementation rules, and the funding and institutional challenges outlined above, Delaware's energy savings targets are considered voluntary.

Established by SB 150, House Amendment 2 in 2014, the EEAC convened to establish guidance on cost-effective energy efficiency programs. The EEAC has established voluntary energy savings targets (electric and gas), similar to the EERS. Utilities and program administrators are encouraged through the EEAC to develop and implement energy efficiency programs that will yield a reduction in electric and natural gas usage. Programs plans are designed around a 3-year timeframe but have the ability to be updated annually, with annual targets increasing each year to reach the cumulative 3-year goal. The incremental energy efficiency targets are incremental annual savings as a percent of forecasted sales: (2016/2017) E – 0.4% G – 0.2%; (2018) E – 0.7% G – 0.3%; (2019) E – 1.0% G – 0.5%.

Last Updated: June 2018

District of Columbia

The Clean and Affordable Energy Act of 2008 (CAEA) requires the Mayor, through DOEE, to contract with a private entity to conduct sustainable energy programs on behalf of the District of Columbia. The CAEA authorizes the creation of a District of Columbia Sustainable Energy Utility (DCSEU) and designates the SEU to be the one-stop resource for energy efficiency and renewable energy services for District residents and businesses.

The DCSEU operates under a performance-based contract with DOEE, with input and recommendations from the SEU Advisory Board, and oversight from the Council of the District of Columbia.

Laws allow for multi-year performance contracts, and as a result DCSEU will be able to operate on a multi-year contract with a 5-year base period and another 5-year extension period. This contract has energy use reduction targets for electricity and natural gas. The target is 0.85% of 2009 electric and gas consumption in D.C. However, this goal is not mandatory and DCSEU earns performance compensation at levels below that.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Florida

Florida does not have an EERS. Past energy reduction targets were not implemented due to insufficient funding, and existing savings goals are negligible.

The Florida Energy Efficiency and Conservation Act (FEECA -- Sections 366.80-85 and 403.519 of the Florida Statutes) established the authority for the Florida Public Service Commission to set targets for energy and peak demand savings and to require each affected utility to develop and implement energy efficiency programs. The Public Service Commission must revisit the goals at least every five years. Specific electricity and peak demand savings goals were set for each of the seven "FEECA utilities" most recently in 2014 for 2015 through 2024, averaging 990.6 GWh annually. These goals are lower than those approved by the Commission in 2009. The Commission identified fewer programs as cost effective due to more stringent building codes and appliance efficiency standards, as well as lower avoided costs resulting from lower natural gas prices. The most recent status of Florida's Energy Efficiency and Conservation efforts for utilities under the Commission's oversight can be found in the Commission's December 2017 FEECA Report. A comprehensive description of the goal-setting process and methodology can be found in Order No. PSC-14-0696-FOF-EU.

Last Updated: July 2018

Georgia

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Hawaii

Summary: Cumulative electricity savings of 4,300 GWh by 2030 (equal to approximately 30% of forecast electricity sales, or 1.4% annual savings).

Hawaii's renewable portfolio standard (RPS) was codified in HRS §269-91, et seq. and amended in 2006, 2008, and 2009. The RPS requires investor-owned utilities and rural electric cooperative utilities to use "renewable electrical energy" to meet 10% of net electricity sales by the end of 2010, 15% by 2015, 25% by 2020, and 40% by 2030. Savings from energy efficiency programs and combined heat and power systems (among other measures) may count towards meeting up to 50% of the standard through 2014. The Public Utilities Commission may assess penalties against a utility for failing to meet the RPS, unless the failure was beyond the reasonable control of the utility.

Beginning in 2015, electrical energy savings will no longer be able to count toward Hawaii's RPS and will instead count towards Hawaii's Energy Efficiency Portfolio Standard (EEPS), which was established in 2009 with the passage of HR 1464. Hawaii's EEPS sets a goal to reduce electricity consumption by 4,300 GWh by 2030 (equal to approximately 30% of forecast electricity sales, or 1.4% annual savings). Renewable displacement or offset technologies, including solar water heating and sea-water air-conditioning district cooling systems, count towards the EEPS after 2015.

The Public Utilities Commission (PUC) must establish interim goals to be achieved by 2015, 2020, and 2025, and may adjust the 2030 standard to maximize cost-effective energy efficiency programs and technologies. The PUC has yet to establish rules for the stand-alone EEPS, including eligible technologies; responsibility for doing so falls on the EEPS Technical Working Group established in 2012. Current energy efficiency targets in Hawaii are set in HI PUC Order, Docket No. 2010-0037 and are subject to revision.

Hawaii has no energy efficiency resource standard in place for natural gas due to the fact that natural gas plays only a minimal role in the state's overall energy portfolio.

Last Updated: August 2018

Idaho

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Illinois

Summary: Electric: Vary by utility, averaging 1.77% of sales from 2018 to 2021, 2.08% from 2022 to 2025, and 2.05% from 2026 to 2030. Natural Gas: 8.5% cumulative savings by 2020 (0.2% incremental savings in 2011, ramping up to 1.5% in 2019).

The scope of energy efficiency activity in Illinois began a dramatic expansion in July 2007 when the state legislature passed the Illinois Power Agency Act (IPAA), which includes requirements for energy efficiency and demand-response programs. The IPAA establishes an EERS that sets incremental annual electric and natural gas savings targets based on the previous year's consumption, beginning on June 1 of that year (see § 220 ILCS 5/8-103). The electric savings requirement began at 0.2% in 2008 and ramped up to a requirement of 2% annual savings in 2015 and thereafter. The natural gas goals began in 2012 with a 0.2% reduction from 2011 sales and ramp up to 1.5% annual savings by 2019 (see Public Act 96-0033). However, due to a 2.0% rate impact cap, regulators had approved lower targets with incremental electric savings targets varying by utility from about 0.5% to 0.7% per year.

Public Act 99-0906 was passed in December 2016 with an effective date of June 1, 2017. The legislation requires ComEd to achieve a cumulative 21.5% reduction and Ameren to achieve a 16% reduction in energy use by 2030, and also requires $25 million per year to be spent on programs to help low-income homes become more efficient. Goals are measured as the change in cumulative savings that consider both newly acquired savings as well as lost savings due to previously administered measures reaching the end of their Expected Measure Life.

Some of the provisions of the Act include adding 220 ILCS 5/8-103B to the Public Utilities Act. This Section shifts responsibility of the DCEO-administered electric efficiency programs to the various utilities. Public Act 99-0906 also revises the gas utility statute (220 ILCS 5/8-104) and assigns the gas utilities the responsibilities that were previously assigned to DCEO as well. Public Act 99-0906 also increases the cost cap (previously 2.0%) to 3.5% for the first four years, 3.75% for the four years that begin in 2022, and 4% for the five years that begin on January 1, 2026. For January 1, 2031 and beyond there is no reference to a cost cap. The new Act also eliminates the provisions for energy efficiency procurement by the Illinois Power Agency.

Last Updated: July 2018

Indiana

Although the state has implemented savings targets in the past, no EERS is currently in place.

Indiana's Commission ordered all jurisdictional electric utilities to begin submitting three-year DSM plans in July 2010, indicating their proposals and projected progress in meeting yearly savings goals outlined by the Commission. The goals began at 0.3% incremental savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019. Load management and direct load control initiatives, including peak-shaving, that result in net-energy savings was counted towards the goal.

The decision also outlined a portfolio of core programs, called Energizing Indiana, offered by all affected utilities. The statewide approach offered consumers a uniform set of energy efficiency programs, using coordinated marketing, outreach, and consumer education strategies. The programs included: residential lighting, home energy audits, low-income weatherization, energy-efficient schools, and commercial and industrial. Energizing Indiana was administered by a single independent, third-party entity, which was contracted by all of the utilities. Utilities were able to oversee additional programs.

In March 2014, the Indiana legislature voted to end Energizing Indiana programs, effectively eliminating the state's EERS. Governor Pence neither signed nor vetoed the bill, and it became law in April 2014. Governor Pence voiced his support for energy efficiency, directing legislators and regulators to consider new frameworks for energy efficiency in the future. The 2015 legislative session of the Indiana General Assembly resulted in SEA 412 (Senate Enrolled Act 412), signed into law by the Governor. SEA 412 requires a public utility to submit an integrated resource plan to the IURC. After 2017, the utilities will be required to seek approval of new energy efficiency plans at least once every three years. Indiana allows utilities to recover the cost of these programs through rates, although certain industrial customers can opt out based on their electric usage. SEA 412 also requires that EM&V procedures be included in an electricity supplier's energy efficiency plan. Additionally, SEA 412 provides that the IURC may not require a third-party administrator to implement an electricity supplier's energy efficiency program or plan.

The IURC is in the process of a rulemaking to update and revise the commission's administrative rules for integrated resource planning and DSM cost recovery.

Indiana Administrative Code provides guidelines for demand-side recovery electric utilities, as well as lost-revenue recovery and demand-side management incentives.

Last Updated: October 2018

Iowa

Summary: For the 2014-2018 planning period, targets varied by utility, with average incremental electricity savings of 1.2% per year and natural gas savings between 0.7% and 1.2% of retail sales. In July 2018, utilities filed new plans with savings 25-50% lower.

Senate File 2386, passed in 2008, requires utilities that are not rate regulated (i.e., municipal utilities and rural cooperatives) to set energy efficiency savings goals, but their plans are not reviewed or approved by the IUB.

For the 2014-2018 planning period, both IPL and MidAmerican set goals of about 1.2% incremental savings per year over this five year period (see Docket No. EEP-2012-0001 and EEP-2012-0002, respectively). Iowa's natural gas utilities also set annual energy efficiency savings targets for the period between 2014 and 2018. These goals vary by utility, set at about 1.2% per year for MidAmerican (Docket No. EEP-2012-0002), 0.9% per year for IPL (Docket No. EEP-2012-0001), and 0.7% per year for Black Hills (Docket No. EEP-2013-0001).

In July 2018, utilities filed new plans with savings 25-50% lower than in the prior period, in Docket No.s EEP-2018-0001, EEP-2018-0002, EEP-2018-0003.

Last Updated: July 2018

Kansas

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2015

Kentucky

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: June 2016

Louisiana

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: September 2016

Maine

Summary: Electric and natural gas savings of 20% by 2020, with annual savings targets of ~1.6% for electric and 0.2% for natural gas.

The Maine Public Utilities Commission (MPUC) approved the first and second Triennial Plan of Efficiency Maine, which develops, plans, coordinates, and implements energy efficiency programs in the state. In the second plan, Efficiency Maine sets a path toward annual energy savings goals in FY2014 of around 1%, ramping up to 1.9% in FY2016. In its third Triennial Plan, Efficiency Maine projects the addition of 2.2% in savings annually. The plan also includes savings targets for other fuels, including natural gas.

The 10- and 20-year targets established by statute are far-reaching and were incorporated into the strategy and budgets of the Triennial Plan. Targets were revised in 2013, when Maine legislators overrode the governor's veto to pass LD 1559. Targets include capturing all cost-effective energy efficiency (both electricity and natural gas); reducing electricity and natural gas consumption 20% by 2020; reducing oil heating use 20% in the same timeframe; and conducting weatherization of all homes for which homeowners are willing to share the costs of cost-effective weatherization to a minimum standard.

Last Updated: July 2018

Maryland

Summary: Beginning in 2016 and through 2023, utilities must ramp up programs by 0.2% per year, leveling out at 2% incremental savings per year as a percent of 2016 weather-normalized gross retail sales and electricity losses.

The EmPOWER Maryland Energy Efficiency Act of 2008 directed the Maryland Public Service Commission (PSC) to require electric utilities in the state to provide energy efficiency services to its customers to achieve 10%

of the 15% per-capita electricity use reduction goal by 2015 calculated against a 2007 baseline (Order 82344). The 15% goal is equivalent to approximately 8,303 GWh. Utility programs must also achieve a reduction in per capita peak demand of at least 5% by end of 2011, 10% by 2013, and 15% by 2015.

The Maryland Energy Administration (MEA) and other public and private stakeholders, including the Department of Housing and Community Development (excluding weatherization programs funded through the EmPOWER Maryland surcharge) aimed toward achieving the remaining 5% of the overall 2015 electricity savings, although no specific legal requirement exists.

Legislative goals ended in 2015. The goals were essentially achieved by the participating utilities with final achievement rates of 99% for the energy savings (MWh) goal and 100% for the peak demand savings (MW) goal. On a per capita basis, the Maryland electric utilities and cooperatives as a whole met the 10% reduction goal for energy use, but did not meet the 15% demand reduction goal, with 11% and 8% achieved respectively.

The PSC issued new EmPOWER targets with Order 87082 in July 2015. The order requires utilities to ultimately achieve savings of 2% per year by ramping up incremental savings at a rate of 0.2% per year beginning in 2016. Work groups were established by the order to determine natural gas goals and limited income goals. The proposals were filed in February 2018 and will be discussed at the semi-annual hearings in May 2018.

The most recent budgets for energy efficiency programs and electricity and natural gas savings can be found in the State Spending and Savings Tables.

Last Updated: June 2018

Massachusetts

Summary: Electric: Yearly incremental savings targets began at 1.4% in 2010, ramping up to 2.94% by 2016. Natural Gas: Targets began at 0.63% in 2010, ramping up to 1.24% by 2016.

The Green Communities Act requires that electric and gas utilities procure all cost-effective energy efficiency before more expensive supply resources, requiring a three-year planning cycle. In January 2016, the DPU approved the third 3-year (2016-2018) electric and gas energy efficiency plans under the Green Communities Act, continuing the state's progress toward the most ambitious energy savings targets in the country. The first electric efficiency procurement plan called for incremental savings 1.0% in 2009, 1.4% in 2010, 2.0% in 2011, and 2.4% in 2012. The state's third three-year plan calls for savings to increase to 2.95% of annual sales in 2018. The energy efficiency investments in 2016-2018 are expected to save 4,118 annual GWh of electricity by 2018. The statewide totals are comprised of individual program administrator savings.

The state's natural gas plan will save 85.8 MMTherms over the 2016 to 2018 plan period (equivalent to 1.24% of sales) and 29.2 MMTherms in the year 2018 (1.25% of sales).

Overall, the fully funded 2016-2018 electric and natural gas efficiency procurement plans will yield net consumer benefits of nearly $7.9 billion. The electric savings proposed in the current three-year plan represent a 5% increase relative to what was achieved in the previous three-year plan; proposed gas savings represent an 8% increase.

Last Updated: July 2018

Michigan

Summary: Electric: 1% annual incremental savings. Natural Gas: 0.75% annual incremental savings. Targets terminate in 2021 for non-rate regulated utilities, representing approximately 10% of Michigan's electric load.

Michigan adopted an EERS in October 2008, when the Clean, Renewable, and Efficient Energy Act was signed into law, requiring all electric and natural gas utilities to provide energy waste reduction programs. PA 295 required electric utilities to achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in each year from 2012 to 2015. Targets continued each year thereafter at 1% incremental electricity savings relative to the prior year's total retail electricity sales. Targets for natural gas utilities started in 2009 at 0.1% savings as a percent of annual retail natural gas sales, eventually ramping up to 0.75% in each year from 2012 to 2015. PA 342, passed in December 2016, maintains the 1.0% (electric) and 0.75% (gas) targets in perpetuity for most utilities, except for non-rate regulated utilities for which targets extend through 2021. An earlier 2% spending cap for electric and natural gas utilities was also removed by the legislation.

Each MWh of savings achieved by a utility in a given year qualifies for one energy waste reduction credit. Excess credits can be "banked", i.e., can be used to meet up to one-third of the required energy savings in the year following the year in which they were achieved. Excess credits cannot be banked if a utility has opted to receive incentive payments for exceeding its savings targets in a particular year.

Regulated investor-owned utilities are responsible for 88.9% of the statewide electric savings targets; municipal utilities represent 7.8% of savings; and electric cooperatives, 3.4%. Most efficiency programs are administered by the utilities, although some have opted to fund a state-selected program administrator, Efficiency United, through an alternative compliance payment mechanism specified in Act 295. Although Efficiency United program services are not subject to the statutory savings targets, equivalent contractual targets were imposed by the Commission. Large electric customers, as determined by their peak use, may administer their own programs.

Last Updated: July 2018

Minnesota

Summary: Electric and Natural Gas: 1.5% incremental savings each year beginning in 2010, adjustable to a minimum of 1% savings.

Minnesota investor-owned electric and gas utilities are subject to the energy savings requirements of the Next Generation Energy Act (NGEA), passed by the Minnesota Legislature in 2007 (Minnesota Statutes 2008 § 216B.241). Among its provisions, the Act set incremental energy-saving goals for utilities of 1.5% of retail sales annually, commencing with the first triennial plan period that began January 1, 2010. Of the 1.5%, the first 1% must be met with direct energy efficiency energy savings, or conservation improvements. This may include savings from efficiency measures installed at a utility's own facilities. The NGEA also allows savings to be achieved indirectly through energy codes and appliance standards. Up to 0.5% may be met by efficiency enhancements to each utility's generation, transmission, and distribution infrastructure.

All electric and natural gas utilities, including municipal utilities and co-operatives, must set energy efficiency spending goals based on a percentage of revenue. Prior to the Next Generation Energy Act going into effect fully in 2010, Minnesota utilities were required to spend a percentage of gross operating revenue (0.5% gas, 1.5% electric, 2% for Xcel Energy's electric utility) on energy efficiency programs rather than to achieve a set amount of energy savings. In practice, however, these minimum spending requirements are often irrelevant, as utilities must spend more than these minimum percentages to achieve the 1.5% EERS.

The NGEA allows a utility to request a lower target (based on historical experience, an energy conservation potential study, and other factors), but for investor-owned utilities that target can be no lower than 1% per year. Lower savings can also be justified if the Commissioner of Commerce determines that additional savings are not cost-effective to ratepayers, the utility, participants, and society. In 2009, the state legislature passed interim legislation to reduce the mandated level of savings during the first three years for natural gas utilities, establishing an interim average annual savings goal of 0.75% over 2010-2012 for utilities that submit a "ramp up" plan that averages annual savings of 1% in subsequent years (Minnesota Session Laws 2009, Ch. 110, Sec. 32).

In the most recent triennial planning period (2013-2015), Xcel Energy electric savings goals were set at 1.38% annually (see Docket No. E,G002/CIP-12-447).

Last Updated: July 2018

Mississippi

There is currently no EERS in place, but new MPSC rules issued in July 2013 establish a comprehensive phase that will set long-term energy efficiency targets.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Missouri

Missouri has only voluntary goals for electric utilities to help the Commission review progress toward an expectation that the utility can achieve a goal of all cost effective demand-side savings including: a) incremental annual energy and demand savings in 4 CSR 240-20.094(2), and b) cumulative annual energy and demand savings in 4 CSR 240-20.094(2)(B), e.g., 0.3% incremental annual energy savings in 2012, ramping up annually to 0.9% in 2015 and 1.7% in 2019 for cumulative annual energy savings of 9.9% by 2020. The voluntary goals are not mandatory, and no penalty or adverse consequence will accrue to a utility that is unable to achieve the annual energy and demand savings goals.

Last Updated: July 2018

Montana

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Nebraska

There is currently no EERS in place. Each of the state's major public power utilities have self-imposed energy efficiency targets, including Omaha Public Power District, Nebraska Public Power District, and Lincoln Electric System.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2017

Nevada

Summary: 25% renewable energy by 2025—energy efficiency may currently meet 20% of the standard in any given year, but phases out of the RPS over time.

In 1997, Nevada established a renewable portfolio standard (RPS) as part of its restructuring legislation. Assembly Bill (AB) 3 in 2005 revised the RPS, increasing the portfolio requirement to 20% by 2015 and allowing utilities to use energy efficiency to help meet the requirements. Amendments in Senate Bill 358 in 2009 raised the portfolio requirement to 25% by 2025. Energy efficiency measures qualify if they are subsidized by the electric utility, reduce demand (as opposed to shifting peak demand to off-peak hours), and are implemented or sited at a retail customer's location after January 1, 2005. AB1 of 2007 expanded the definition of efficiency resources to include district heating systems powered by geothermal hot water. For years 2015 to 2019 not more than 20 percent of the RPS can be met utilizing energy efficiency. This amount drops to 10 percent for calendar years 2020 to 2024 before reducing to zero for 2025.

The Public Utilities Commission of Nevada (PUCN) established a program to allow energy providers to buy and sell portfolio energy credits (PECs) in order to meet energy portfolio requirements. The number of kWh saved by energy efficiency measures is multiplied by 1.05 to determine the number of PECs. For electricity saved during peak periods as a result of efficiency measures, the credit multiplier is increased to 2.0. PECs are valid for a period of four years. The PUCN currently has an open rulemaking regarding the annual savings goals in Docket Nos. 17-07011 and 17-08023.

In 2013, the legislature voted to phase out this energy efficiency allowance in order to effectively increase the requirement for new renewable energy.

In June 2017, SB 150 was signed into law directing the PUCN to establish annual energy savings goals for NV Energy and to establish performance-based incentives that an electric utility can recover if it exceeds those goals.

Nevada has no natural gas EERS.

Last Updated: July 2018

New Hampshire

Summary: Incremental electric savings of 0.8% in 2018, ramping up to 1.0% in 2019, and 1.3% in 2020. Natural gas savings of 0.7% in 2018, 0.75% in 2019, and 0.8% in 2020.

The Commission approved the implementation of an EERS for 2018-2020 for the state's gas and electric utilities in EERS Order No. 26-095 on January 2, 2018.

In August 2016, the New Hampshire Public Utilities Commission approved an EERS to help the state achieve the objectives set out in its 10-year State Energy Strategy. Commission-approved energy efficiency programs will be implemented in accordance with this framework beginning January 1, 2018. The EERS has an overarching goal of achieving all cost-effective energy efficiency, which it hopes to achieve incrementally through a framework of three-year planning periods. During the first three-year period, the cumulative goal for electric savings will be 3.1% of delivered 2014 kWh sales, with interim annual savings goals of 0.80%, 1.0%, and 1.3%. The cumulative goal for gas savings will be 2.25% of delivered MMBtu 2014 sales, with interim annual savings goals of 0.70%, 0.75%, and 0.80%. Funding for the EERS will come from increases to the system benefits charge (SBC) and the local distribution adjustment charge (LDAC), both current components of electric and gas bills, respectively.

The New Hampshire Senate passed HB 1129 in 2014, calling for the development of long term goals that take into account and complement any goals developed by the New Hampshire Public Utilities Commission. In February 2015, NHPUC staff issued a straw proposal for an EERS for the period 2015-2025. For electricity savings, staff assumed a gradual increase in savings from 2015 to 2025 and determined total savings of about 9.76% of 2012 kWh electrical usage were attainable over the period.

In December 2015, testimony was filed proposing frameworks and general terms for the implementation of an EERS in New Hampshire. A Settlement Agreement, including the establishment of an EERS, was approved by the Commission in Order No. 25,932 in August 2016.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

New Jersey

In May 2018 New Jersey adopted an EERS when the governor signed clean energy bill A3723, which features 2% electric and 0.75% gas savings goals. In April, consultants presented the New Jersey Board of Public Utilities with the draft strategic plan for 2019-2022 for the statewide Clean Energy Program, including an energy efficiency portfolio achieving a 56% increase in savings by 2022.

Last Updated: July 2018

New Mexico

Summary: 5% reduction from 2005 total retail electricity sales by 2014, and an 8% reduction by 2020.

In 2008, New Mexico legislature passed HB 305, which amended the Efficient Use of Energy Act (first passed in 2005) and established energy efficiency targets for the state. The 2008 law required investor-owned utilities to achieve a 5% reduction from 2005 total retail electricity sales by 2014 and a 10% reduction by 2020 (see NM Stat. § 62-17-1 et seq.).

The state's targets were amended in 2013 with the passage of HB 267. The law established a fixed tariff rider for funding energy efficiency and load management programs. The bill was a compromise among energy efficiency advocates, New Mexico's utilities, and representatives of the Public Regulation Commission, and preserved the targets but reduced the energy savings requirement in 2020 for electric utilities from 10% to 8% of sales.

Though targets have been adjusted downward, steady funding makes it likely that long-term targets will be surpassed. If a utility determines it cannot achieve the energy saving requirements, it must report to the Commission, explain the shortfall, and propose alternative requirements based on acquiring cost-effective and achievable energy efficiency and load management resources. If the commission determines that the requirements exceed the achievable amount of energy efficiency and load management available, it may establish lower requirements for the utility (see NMAC 17.7.2).

Distribution cooperative utilities, which are not fully regulated by the PRC, must annually consider self-imposed electricity reduction targets and design demand-side management programs to enable them to meet those targets. Each cooperative utility must submit a report to the PRC annually describing their demand-side management efforts from the previous year.

New Mexico has no natural gas EERS.

Last Updated: July 2018

New York

Summary: The 2025 State Energy Plan 2025 target 185 Tbtu savings (see New Efficiency, New York report), which will be approximately 3% of incremental electric sales. The PSC has yet to establish specific incremental annual energy savings targets for each utility.

In January 2017, the PSC authorized NYSERDA's Clean Energy Fund (CEF) framework, which outlines a minimum 10-year energy efficiency goal of 10.6 million MWh measured in cumulative first-year savings.

Previously, under the Reforming the Energy Vision (REV) proceedings, electric tilities filed efficiency transition implementation plans (ETIPS) with incremental targets varying from 0.4% to 0.9% for the period 2016–18. Natural gas utilities filed proposals for varying incremental targets with incremental savings averaging 0.28% for the period 2016–18.

In 2008, the New York State Public Service Commission established the New York Energy Efficiency Portfolio Standard (EEPS) proceeding. As part of a statewide program to reduce electricity usage by 15% of the forecast levels by the year 2015, with comparable results in natural gas conservation, the Commission established interim targets and funding through the year 2011. The Commission required utilities to file energy efficiency programs, and NYSERDA, as well as independent parties, were invited to submit energy efficiency program proposals for Commission approval.

Through a series of Orders, the Commission authorized the utilities (the six electric investor-owned utilities previously authorized in the SBC proceeding, plus Corning National Gas Corporation, St, Lawrence Gas, Company, Inc., KeySpan Energy Delivery New York, and KeySpan Energy Delivery Long Island) as well as NYSERDA to conduct EEPS programs. Since June 2008, the Commission approved over 100 electric and gas energy efficiency programs, along with rules to guide implementation and measure results.

In 2011, the Commission reauthorized a majority of the EEPS programs for the four-year period ending December 31, 2015, with revised targets and budgets where appropriate. NYSERDA was authorized to operate a limited number of programs through December 31, 2018. Additionally, three gas efficiency programs run by National Fuel Gas Corporation pursuant to its rate cases were consolidated into the EEPS program. The percentage of funding allocated to low-income programs was also increased. The order also suspended a portion of the program that provides utilities with financial incentives for achieving efficiency targets. These incentives were reinstated in March 2012 for the period 2012-2015.

In 2014, New York initiated a proceeding, Case 14-M-0101, "Reforming the Energy Vision," to further discuss the state's energy efficiency resource standard, along with other major elements of the state's utility regulatory structure. The PSC's Phase I REV Decision establishes minimum savings goals of only 0.37% for utilities in 2016, and it requires utilities to file energy efficiency plans in 2016-2018 but does not specify specific energy savings goals.

On February 26, 2015, the Commission issued an order in Case 14-M-0101 that, among other things, established a new framework for post-2015 electric energy efficiency programs. A similar framework is expected to be established for gas energy efficiency programs—a Notice of Proposed Rulemaking was published in the NYS Register on April 15, 2015. A new case, 15-M-0252, was established for the utilities post-2015 energy efficiency programs.

In January 2016, the PSC authorized NYSERDA's Clean Energy Fund (CEF) framework, which outlines a minimum 10-year energy efficiency goal of 10.6 million MWh measured in cumulative first-year savings. In May 2016, the PSC issued a REV II Track Order prescribing that the Clean Energy Advisory Council also propose utility targets supplemental to utilities' Efficiency Transition Implementation Plans (ETIPS) by October 2016. Some degree of overlap of program savings is anticipated between utility targets and NYSERDA CEF goals.

Last Updated: July 2018

North Carolina

Summary: Renewable Energy and Energy Efficiency Portfolio Standard (REPS): 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.

North Carolina Senate Bill 3 was finalized in 2008, introducing the state's combined Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under REPS, public electric utilities in the state must obtain renewable energy power and energy efficiency savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018, and 12.5% in 2021 and thereafter. For IOUs, energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target. Co-operative and municipal utilities may satisfy all of their REPS requirement of 10% savings by 2018 with energy efficiency, excluding small set-asides for solar and other resources. Utilities demonstrate compliance by procuring renewable energy credits (RECs) earned after January 1, 2008. Under North Carolina Utility Commission rules, an REC is equivalent to 1 MWh of electricity generated by a renewable energy facility or avoided through an efficiency measure.

Since the REPS goals are cumulative, the 12.5% target in 2021 will require 5% of its sales in 2021 to be met with energy efficiency *over the entire 13-year period* in which energy efficiency savings may be counted. Averaged over three years, each target period until 2018 requires yearly incremental savings of 0.25%. The final period from 2018 to 2020 will allow yearly incremental energy savings of 0.83%. Utilities plan to employ more than the full quarter allowable over the next ten years. Industrial customers may opt-out of utility energy efficiency programs and not bear the costs of new programs if they implement their own programs.

Each electric power supplier must file a REPS compliance plan for Commission review as part of its Integrated Resource Planning (IRP) filing on or before September 1 of each year. A utility's IRP filing must include a comprehensive analysis of all resource options considered by the utility, including demand-side management and energy efficiency, which must result in "the least cost mix of generation and demand reduction measures achievable…."(N.C. Gen. Stat. §62-2(3a)). According to Commission Rule R8-60, IRP filings must include a 15-year forecast of demand-side resources, among other requirements for the assessment and characterization of the demand-side resource.

North Carolina has no natural gas EERS.

Last Updated: July 2018

North Dakota

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2017

Ohio

Summary: Beginning in 2009, incremental savings of 0.3% per year are required, ramping up to 1% in 2014. A "freeze" in 2015–2016 allows utilities who have achieved 4.2% cumulative savings to reduce or eliminate program offerings.

In 2014, Ohio froze its energy efficiency resource standard. Prior to that, the EERS had encouraged significant levels of savings within the state. Future targets remain uncertain.

Senate Bill 221, signed into law May 1, 2008, included both an Energy Efficiency Portfolio Standard (EEPS) and Alternative Energy Portfolio Standard (RPS), among other provisions. For efficiency, the law required a gradual ramp up to a cumulative 22% reduction in electricity use by 2025. Beginning in 2009, the Act required investor-owned utilities and retail suppliers to implement energy efficiency programs that achieve energy savings equal to at least three-tenths of 1% of sales. The baseline for which energy savings were calculated against is the average number of total kilowatt hours sold by electric distribution utilities during the preceding three years.

Ohio's EEPS also included peak demand reduction targets of 0.75% annually through 2018.

Last Updated: September 2016

Oklahoma

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Oregon

Summary: Electric: Targets are equivalent to 1.4% of electric sales from 2014 through 2019. Natural Gas: 2015-2019 gas targets are equivalent to 0.7% of forecasted sales.

In its first ever long-range strategic plan, the Energy Trust of Oregon laid out energy savings goals between 2010 and 2014 of 256 average megawatts (2,242.6 GWh) of electricity and 22.5 million annual therms of natural gas. These goals include savings from NEEA programs. Electric targets were equivalent to 0.8% of 2009 electric sales in 2010, ramping up to 1% in 2013 and 2014. Natural gas targets ramped up from 0.2% of 2007 natural gas sales to 0.4% in 2014.

In its second long-range strategic plan, Energy Trust laid out energy savings goals for the years 2015 through 2019 of 240 average megawatts (2,102 GWh) and 24 million annual therms of natural gas. These goals include savings from market transformation programs. Electric targets were set to an estimated 1.4% of electric sales forecasted for 2014 through 2019. Natural gas targets are set at approximately 0.7% of forecasted natural gas sales for the same five-year time period.

Annual goals for Energy Trust reflect an increment in their Strategic Plan goal. These annual goals are codified by the OPUC and then incorporated into each utilities' Integrated Resource Plan (IRP), along with a 20-year forecast of achievable, technical energy efficiency potential. In this sense, Energy Trust's IRP goals represent a *minimum* resource standard and energy efficiency savings supplied by Energy Trust function as a resource supplied each year to the utilities to meet their IRP goals.

Achievement of Oregon's goals is contingent upon continued increases in IRP funding. Goals include savings from NEEA programs.

Last Updated: August 2018

Pennsylvania

In August 2012, the Pennsylvania PUC issued an implementation order for Phase II of the EE&C Program, establishing electricity savings targets for the 3-year period from FY2014-2016. The targets amount to 2.3% cumulative savings over the 3-year period; no incremental annual targets were established.

On June 11, 2015, the Commission adopted additional incremental reductions in consumption for a Phase III of the Act 129 Energy Efficiency and Conservation Program. Phase III began on June 1, 2016, and will end on May 31, 2021. Phase III requires a cumulative average savings of approximately 3.7% (range of 2.6% to 5.0%) from EE and also includes a DR requirement with average annual savings of 425 MW. (See pages 35 and 57 of the implementation order, Docket #M 2014-2424864, for details on DR and EE, respectively).

Pennsylvania has no natural gas EERS although three natural gas distribution companies have submitted voluntary Energy Efficiency & Conservation (EE&C) plans.

Last Updated: June 2018

Rhode Island

Summary: Electric: 1.7% in 2012 ramping up to 2.6% by 2017. Natural Gas: ~0.4% of sales in 2011 ramp 1.1%.

The Rhode Island legislature unanimously passed the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 in June 2006. This act establishes a Least Cost Procurement mandate, requiring utilities to acquire all cost-effective energy efficiency with input and review from the Energy Efficiency and Resource Management Council (EERMC). Under the Least Cost Procurement mandate, National Grid is required to participate in strategic long-term planning and invest in all energy efficiency that is cost-effective and cheaper than supply on behalf of its customers.

The act also established requirements for strategic long-term planning and purchasing of least-cost supply and demand resources. Utilities must submit 3-year and annual energy efficiency procurement plans, which offer program details, as well as spending and savings goals. Hearings are held once a year before the Rhode Island Public Utilities Commission to review program plans. Yearly incremental savings goals for electricity during the 2012-2014 period began at 1.7%, increasing to 2.5% in 2014 (Docket 4284, 4295). Targets for 2015-2017 range from 2.5% to 2.6% (Docket 4443).

Rhode Island's EERS policy also includes natural gas targets. Savings goals for the 2012-2014 period ranged from 0.6% in 2012 to 1.0% in 2014 (Docket 4284, 4295). Targets for 2015-2017 range from 1% to 1.1% (Docket 4443).

Last Updated: July 2018

South Carolina

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2016

South Dakota

There is currently no EERS in place.

Utilities may voluntarily participate in the state's Renewable, Recycled, and Conserved Energy Objective (ARSD 20:10:38). Energy efficiency counts toward this objective.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: July 2018

Tennessee

The Tennessee Valley Authority (TVA) stated in its 2008 Environmental Policy that in order to meet its objective of reducing the rate of carbon emissions, it needed to reduce load growth by at least one-quarter over five years through energy efficiency and demand-side initiatives.

In its 2011 integrated resource plan, TVA included savings goals from energy efficiency and demand-response in its recommended planning direction. The goals included reductions in peak demand of 3,600-5,100 MW and energy savings of 11,400-14,400 GWh to be met by the year 2020. These ranges include savings already achieved through 2010, when the planning process began. The degree to which these goals are binding in the long term is unclear and therefore is not considered an EERS.

Last Updated: July 2018

Texas

Summary: 20% Incremental Load Growth in 2011 (equivalent to ~0.10% incremental savings per year); 25% in 2012, 30% in 2013. After 2013, the goal metric is shifting to 0.4% of peak.

In 1999, Texas became the first state to establish an energy efficiency resource standard, requiring electric utilities to offset 10% of load growth through end-use energy efficiency (Texas Senate Bill 7). Demand growth is the average growth of the five previous weather-adjusted peak demands for each utility. In 2007, after several years of meeting this goal at low costs, the legislature increased the standard to 15% of load growth by December 31, 2008, and 20% of load growth by December 31, 2009 (Texas House Bill 3693). The legislation also required utilities to submit energy savings goals. The Public Utility Commission of Texas (PUCT) approved these rules in March 2008.

While the 2007 legislation required utilities to submit GWh savings goals to ensure they did not overly focus on load management, the PUCT determined that utilities could convert their demand savings goals into corresponding energy savings goals. In practice, however, the energy savings (MWh) resulting from Texas utility demand-response and energy efficiency programs are about twice the amount of the energy saving goals.

In 2010, the PUCT approved Substantive Rule § 25.181, which increased the goals from 20% of electric demand growth to 25% growth in demand in 2012 and 30% in 2013. The rule also established customer cost caps to limit efficiency expenditures. The cost caps may not affect every utility, but some have already hit the caps, which are inhibiting investment in cost-effective energy efficiency programs.

In the 2011 legislative session, Texas adopted Senate Bill 1125, which amends the EERS policy by requiring utilities to eventually achieve savings of 0.4% of each company's peak demand. As a result, utilities with rapidly growing load growth will have more predictable and consistent goals than those that were set based on load growth. The Bill also added focus on reducing demand in the winter. The Bill does not remove the cost caps adopted in 2010.

Texas has no natural gas EERS.

Last Updated: July 2017

Utah

In 2008, Utah adopted a renewable portfolio standard (RPS) of 20% by 2025, subject to cost-effectiveness, that allows energy savings from DSM measures to qualify towards the standard without any cap.

Last Updated: June 2018

Vermont

Summary: Average yearly incremental electricity savings of about 2.3%, 2015-2017

Vermont does not have traditional EERS legislation with a set schedule of energy-savings percentages for each year. Instead, Vermont law requires EEU budgets to be set at a level that would realize "all reasonably available, cost-effective energy efficiency." Compensation and specific energy-savings levels—not "soft" goals or targets—are then negotiated with EEU contractor Vermont Energy Investment Corporation (VEIC). There is not an explicit penalty for non-performance. However, a portion of the compensation Vermont pays the administrator is contingent on meeting stated goals, subject to a monitoring and verification process. If the administrator does not meet stated goals, the state will withhold compensation, and the administrator potentially will be replaced at the end of the three-year period (DSIRE 2011).

Vermont Public Service approved a 2012-2014 budget for Efficiency Vermont, set to achieve approximately 2% annual savings (VT Public Service Board Docket EEU-2010-06). Electric efficiency quality performance indicators for 2015-2017 include a target for total electricity savings of 321,800 MWh over the three-year period for Efficiency Vermont. Burlington Electric also has savings targets in place for this period, bringing statewide incremental electricity savings targets to about 2.1% per year.

The goal-setting process has changed due to Vermont's "order of appointment" franchise-like structure. Every three years, a "demand resources plan" proceeding will be held. The proceeding will set budgets and goals for the next 20 years, coinciding with the long-range transmission plan to allow for integration of forecasting (EEU Structure Docket 7466).

VEIC and BED have been awarded Orders of Appointment as Energy Efficiency Utilities for a period of 12 years. Every 6 years there is a review as to if this appointment should be extended an additional 6 years. The 2015-2017 budget is set to achieve a 2.25% level of savings increasing to 2.32% by 2017 (EEU-2013-01 2013-2014 Demand Resources Plan Proceeding 7/9/2014).

Vermont Gas Systems has also been designated an EEU with a 12-year Order of Appointment to deliver natural gas energy efficiency services as of April 2015 (see Docket 7676).

Last Updated: August 2018

Virginia

In March 2007, the Virginia legislature passed a bill amending Virginia's earlier electric industry restructuring law. The governor approved the bill conditionally, requiring the addition of a section on energy conservation, including a goal of 10% electricity savings by 2022 (calculated relative to 2006 sales). The legislature accepted this condition. Under this provision, the State Corporation Commission (SCC) was directed to conduct a proceeding to consider whether the 10% goal could be met cost-effectively, determine the mix of programs that should be implemented and their cost, and develop a plan for development and implementation of these programs, including who should deploy and administer these programs. The SCC completed a report verifying the energy efficiency goal of 10% by 2022 was achievable. In 2015, Governor McAuliffe announced a revised goal of 10% electricity savings by 2020. However, no regulatory requirements have been put in place for energy efficiency programs, so energy savings goals are considered voluntary.

Last Updated: July 2018

Washington

Summary: Utilities set biennial targets to achieve all cost-effective electricity conservation. Targets average ~1.4% incremental electricity savings per year.

Washington voters approved ballot initiative 937, the Energy Independence Act, in November 2006, which set new renewable energy resource and conservation requirements for large electric utilities to meet. The law, codified in Chapter 19.285 RCW, had rules adopted for its implementation in 2007 and 2008 (WAC 480-109, WAC 194-37). The energy conservation section requires each qualifying utility (those with more than 25,000 customers in Washington) to "pursue all available conservation that is cost-effective, reliable and feasible." Seventeen utilities, both publicly-owned and investor-owned, currently meet the definition of qualifying utility.

The law requires utilities to use methodologies consistent with the Northwest Power and Conservation Council's (NPCC) to determine their achievable ten-year cost-effective conservation potential and update that potential assessment every two years. Utilities also must establish a biennial acquisition target beginning in 2010-

2011 and update that target every two years. If a utility does not meet its conservation goals, it must pay an administrative fine for each MWh of shortfall, starting at $50 and adjusting annually for inflation beginning in 2007.

Although Washington does not have a natural gas EERS, in 2014, all four investor-owned natural gas utilities committed to funding a 5-year, $18.3 million natural gas market transformation pilot through the Northwest Energy Efficiency Alliance. The three largest initiatives have the potential to produce over 280 million therms of savings per year with an average 20-year levelized cost of $0.28/therm.

Last Updated: July 2018

West Virginia

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here.

Last Updated: October 2018

Wisconsin

Summary: Electric: 0.77% of sales in 2015-2018. Natural Gas: 0.6% of sales in 2015-2018.

2005 Wisconsin Act 141 directs the Public Service Commission to establish energy efficiency and renewable goals and measureable targets at least every four years. The PSCW issued its final order of the Quadrennial Planning Process on November 10, 2010, which adopted electricity and natural gas savings goals for Focus on Energy. The electricity goals, as a percent of peak load and electric sales, amounted to 0.75% in 2011, ramping up to 1.5% in 2014. The PSC also approved natural gas goals of 0.5% in 2011, ramping up to 1% in 2013.

Shortly after the EERS was approved by the Joint Finance Committee of the state legislature, the state limited funding to Focus on Energy to 1.2% of revenues, which resulted in a major reduction in energy efficiency goals. The goals are now approximately 0.75% of sales in 2011, 2012, and 2013 for electricity and 0.5% of sales for natural gas over the same time frame.

In December 2014, the Statewide Energy Efficiency and Renewables Administration finalized the Focus on Energy contract for the years 2015-2018. The contract included a requirement that Focus on Energy programs achieve cumulative net first-year electricity savings of 2,137,142,988 kWh and natural gas savings of 76,911,727 over the four-year period. 2015-18 electric goals were slightly adjusted to reflect additional funding of rural programs. The net first-year kWh goal has been slightly increased from the database figure to 2,261,492,068 kWh, while the gas goal remains the same.

The Commission in May 2018 set four-year savings goals for the 2019-2022 period, which were guided by the findings of Focus' 2017 potential study regarding total achievable potential available at Focus' $100 million annual funding level. All goals are now set in lifecycle terms, rather than the annual terms the Commission previously used. The order has not been formally issued yet, but total Commission net goals are 224,666,366 MMbtu with minimum fuel-level goals of 22,831,730,001 kWh, 1,242,978,665 therms, and 349,213 kW. The program administrator will also have gross lifecycle savings goals of 299,555,154 MMBtu, 30,442,306,668 kWh, 1,657,304,887 therms, and 465,617 kW.

Last Updated: June 2018

Wyoming

There is currently no EERS in place.

For more information on Energy Efficiency Resource Standards, click here

Last Updated: July 2016

EXHIBIT TW/EM – 28

RESPONSE TO SIERRA CLUB 3-16

<u>**Virginia Electric and Power Company**</u>
<u>**Case No. PUR-2018-00168**</u>
<u>**Sierra Club**</u>
<u>**Third Set**</u>

The following response to Question No. 16 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No.16

Refer to Hubbard's Testimony, Schedule 3. Explain why the approved programs were terminated rather than extended for longer implementation. Specifically:

a. Explain why the approved Phase I programs (Residential Lighting, Residential Low-Income, Non-Residential Lighting, Non-Residential HVAC) were terminated rather than extended for longer implementation;
b. Explain why the approved Phase II programs (Residential Home Energy Checkup, Residential Duct Sealing, Residential Heat Pump Upgrade, Residential Heat Pump Tune-up, Non-Residential Energy Audit, Non-Residential Duct Testing and Sealing) were terminated rather than extended for longer implementation;
c. Explain why the approved Phase IV program (Residential Appliance Recycling) was terminated rather than extended for longer implementation?

Response:

a. Ultimately, the State Corporation Commission ("SCC") issues a Final Order that outlines the approved/denied proposed Programs, the approval period for each Program, and the total cost cap for each Program. Additionally, each Program measure has a specified life and is impacted by the evolving market shifts toward newer technologies and code changes. Lastly, all proposed Program extensions must pass the cost-benefit tests when seeking approval for Program extensions. Each of these factors impact the feasibility of the Company seeking extensions for specific Programs.

b. See the Company's response to Sierra Club Set 3-16(a) above. The Company further notes that it filed for an extension of the Residential Heat Pump Upgrade Program in

Case No. PUE-2016-00111, which was denied by the SCC in its Final Order issued on June 1, 2017.

c. See the Company's response to Sierra Club Set 3-16(a) above.

EXHIBIT TW/EM – 29

RESPONSE TO SIERRA CLUB 3-14

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 14 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No. 14

Refer to Hubbard's Testimony, at 7. Please elaborate on the process and costs to re-launch the Residential Income and Age Qualifying Home Improvement Program.

a. Were additional costs incurred to re-launch the program rather than if the program had continued without interruption?
b. How long was the program unavailable to customers?
c. Was program participation impacted by the re-launch?
d. Were vendors and contractors impacted by the re-launch?

Response:

a. Yes. The Company's vendor partner included start-up costs as part of its bid.

b. The DSM Phase IV Residential Income and Age Qualifying Home Improvement Program was not available to customers from January 1, 2018 - June 30, 2018.

c. Yes, program participation was impacted, but in a different way than most of the Company's other DSM programs. Since the Company has its own shareholder-funded low income program through EnergyShare, eligible low-income customers were not turned away, but were instead directed to the EnergyShare program. Thus, there was not a backlog of customers that needed to be served immediately upon re-launch of the DSM Phase IV Residential Income and Age Qualifying Home Improvement Program in the summer of 2018.

d. Yes. Once the re-launch occurred, the vendors and contractors had to expand the number of resources available to handle the additional capacity.

EXHIBIT TW/EM – 30

RESPONSE TO SIERRA CLUB 3-15

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Third Set

The following response to Question No. 15 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 10, 2019 has been prepared under my supervision.

Michael T. Hubbard
Manager, Energy Conservation
Virginia Electric and Power Company

Question No. 15

Refer to Hubbard's Testimony, at 13-14. For the three non-residential programs to be re-launched in 2019, please explain whether the program will be unavailable to customers for a period of time. If so, please elaborate on the process and costs to re-launch these programs.

Response:

It is important to note that the three newly proposed Programs discussed in Company Witness Hubbard's testimony at pages 13-14, the DSM Phase VII Non-residential Lighting Systems & Controls Program, the Non-residential Heating and Cooling Efficiency Program, and the Window Film Program, are not extensions of the Company's DSM Phase III Programs. While the Programs are conceptually similar, the program designs and specifics proposed therein vary from the past DSM Phase III Programs and therefore are not a "re-launch" of the DSM Phase III Programs.

EXHIBIT TW/EM – 31

RESPONSE TO SIERRA CLUB 4-6

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 6 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Lisa R. Crabtree
McGuireWoods LLP

Question No. 6

Please provide retail sales for customers that are eligible to participate in all of the Company's programs (Phases I-VII), broken out separately by residential and nonresidential, and for each year in 2012 through 2017.

Response:

The Company objects to this request on the grounds that it requires original work, which is not required by Rule 260 of the Commission's Rules of Practice and Procedure, 5 VAC 5-20-260. The Company further objects on the grounds that the requested information is not relevant to the current application or reasonably calculated to lead to the discovery of admissible evidence. Determining the number of eligible customers for a given program depends on a number of factors, including whether the customer has previously participated and for, non-residential customers, the historical demand. Constructing this historical data on an annual and program-specific basis would be extremely time-consuming and has not been conducted by the Company.

EXHIBIT TW/EM – 32

EIA 861 DATA WEBSITE

U.S. Energy Information Administration

lectricity

lectric power sales, revenue, and energy efficiency Form EIA-861 detailed data iles

Release date: October 12, 2018
Next release date: November 2019
Re-released: January 15, 2019 Correction/revision notices

The Form EIA-861 and Form EIA-861S (Short Form) data files include information such as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity.

The EIA-861S was created in 2012 in an effort to reduce respondent burden and to increase EIA's processing efficiency. Approximately 1,100 utilities completed this form in lieu of the EIA-861. The short form has fewer questions and collects retail sales data as an aggregate and not by customer sector. EIA has estimated the customer sector breakdown for this data and has included it in the file called "Retail Sales." Advanced metering data and time-of-use data are collected on both Form EIA-861 and Form EIA-861S.

In 2012, the data files were renamed to help users find the data. Data files prior to 2012 retained their original names, and, in the description below, the prior names are referred to as "Formerly."

Green pricing and demand-side management data were no longer collected after 2012. In 2013, demand-side management data started being collected as energy efficiency and demand response data. Sales to Ultimate Customer, Customer Sited is a new file; this data was previously in Retail Sales as ownership code “unregulated.” Also new in 2013, were the number of distribution circuits (Distribution Systems) and SAIDI* and SAIFI** (Reliability) data.

- **Frame** – This file, compiled from data collected on both Forms EIA-861 and EIA-861S, contains a complete list of all respondents from both forms and a list of each file they are in.
- **Advanced Meters –** This file, compiled from data collected on both Forms EIA-861 and EIA-861S, contains information on Automated Meter Readings (AMR) and Advanced Metering Infrastructure (AMI). (Formerly File 8)
- **Balancing Authority –** This file, contains the list of Balancing Authorities and the states they operate in, for the EIA-861 and EIA-861S. (Formerly File 1_cao)
- **Demand Response** (2013 forward) – This file, compiled from data collected on Form EIA-861 only, contains the number of customers enrolled, energy savings, potential and actual peak savings, and associated costs.
- **Distribution Systems** (2013 forward) – This file, compiled from data collected on Form EIA-861 only, contains the number of distribution circuits and circuits with voltage optimization.
- **Dynamic Pricing** (2013 forward) – This file, compiled from data collected on Form EIA-861 only, contains the number of customers enrolled in various programs, i.e. time of use, real time, variable peak and critical peak pricing, and critical peak rebate programs.
- **Energy Efficiency** (2013 forward) – This file, compiled from data collected on Form EIA-861 only, contains incremental and life cycle data

Year	Format
2017	ZIP
2016	ZIP
2015	ZIP
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on energy savings, peak demand savings, weighted average life, and associated costs.

- **Mergers** (2007 forward) – This file, compiled from data collected on Form EIA-861 only, contains information on mergers and acquisitions. (Formerly File 7)
- **Net Metering** (2007 forward) – This file, compiled from data collected on Form EIA-861 only, contains number of customers and displaced energy, by sector and state. For 2010 forward, it contains capacity, customer count, and energy sold back (an optional question on the survey) by sector and state and by technology type, i.e. photovoltaic, wind, and/or other.
- **Non Net Metering Distributed** – This file, compiled from data collected on Form EIA-861 only, contains information on utility or customer-owned distributed generators such as the number, capacity, and technology type of generators. Capacities by photovoltaic and storage generation types were added in 2010, fuel cells were added in 2016. Starting in 2016, this data is now collected at the sector level. (Formerly Distributed Generation, Formerly File 6)
- **Operational Data –** This file, compiled from data collected on Form EIA-861 only, contains aggregate operational data for the source and disposition of energy and revenue information from each electric utility in the country, including power marketers and federal power marketing administrations. (Formerly File 1)
- **Reliability** (2013 forward) – This file, compiled from data collected on Form EIA-861 only, contains SAIDI and SAIFI data.
- **Sales to Ultimate Customers –** This file, compiled from data collected on the Form EIA-861 and an estimate from Form EIA-861S for data by customer sector, contains information on retail revenue, sales, and customer counts by state, balancing authority, and class of service (including the transportation sector which was added in 2003) for each electric distribution utility or energy service provider. (Formerly File 2)
- **Sales to Ultimate Customers, Customer Sited –** This file, compiled from data collected on the Form EIA-923 only, contains information on retail revenue, sales, and customer counts by state and balancing authority. This includes retail sales from any units located at a customer site.
- **Service Territory –** This file, compiled from data collected on the Form EIA-861 and Form 861S, contains the names of the counties, by state, in which the utility has equipment for the distribution of electricity to ultimate consumers. (Formerly File 4)
- **Short Form** (2012 forward) – This file, compiled from data collected on the Form EIA-861S in aggregate, contains information on retail revenue, sales, and customer counts by utility, by state.
- **Utility Data** (2007 forward) – This file, compiled from data collected on Form EIA-861 only, contains information on the types of activities each utility engages in, the NERC regions of operation, whether the utility generates power, whether it operates alternative-fueled vehicles, and, beginning in 2010, the ISO or RTO region in which the entity conducts operations. (Formerly File 1_a)
- **Demand-Side Management** (discontinued after 2012) – This file, compiled from data collected on both Form EIA-861 and, for time-based rate programs, Form EIA-861S, contains information on electric utility demand-side management programs, including energy efficiency and load management effects and expenditures. Beginning in 2007, it also contains the number of customers in time-based rate programs. (Formerly File 3)
- **Green Pricing** (discontinued after 2012) – This file, compiled from data collected on Form EIA-861 only, contains number of customers, sales, and revenue, by sector and state. (Formerly File 5)

Note: All sales data, including energy efficiency savings, are in megawatthours. Peak and peak reduction data are in megawatts for 2001 forward and kilowatts for previous years. Revenue and expenditure data are in nominal thousand-dollar units.

*System Average Interruption Duration Index

**System Average Interruption Frequency Index

Contact: Electricity data experts

EXHIBIT TW/EM – 33

SELECTIONS FROM ACEEE SCORECARDS FROM 2013-2018, SAVINGS AS PERCENT OF SALES

Appendix B. 2012 and 2013 Savings Data Disaggregated

State	2012 electric program savings (MWh)	Savings as % of retail sales	2012 natural gas program savings (MMTherms)	Savings as % of retail sales*	2013 electric program savings (MWh)	Savings as % of retail sales	2013 natural gas program savings (MMTherms)	Savings as % of retail sales*
Alabama	5,6045	0.06%	—	—	—	—	—	—
Alaska	1,517	0.02%	—	—	—	—	—	—
Arizona	1,244,555	1.66%	3.30	0.49%	1,317,329	1.74%	—	—
Arkansas	142,187	0.30%	3.34	0.48%	227,531	0.49%	5.19	0.75%
California	2,130,000	0.82%	24.50	0.33%	1,701,601	0.66%	31.00	0.41%
Colorado	419,237	0.78%	4.80	0.28%	472,000	0.88%	6.10	0.36%
Connecticut	322,102	1.09%	3.70	0.43%	285,817	0.97%	4.80	0.56%
Delaware	8,450	0.07%	0.17	0.09%	8,809	0.08%	0.10	0.05%
District of Columbia	24,054	0.21%	0.05	0.02%	52,303	0.47%	0.50	0.18%
Florida	587,083	0.27%	—	—	—	—	—	—
Georgia	241,261	0.18%	—	—	288,140	0.22%	—	—
Guam	—	—	—	—	—	—	—	—
Hawaii	120,070	1.25%	—	—	159,056	1.67%	—	—
Idaho	188,245	0.80%	—	—	—	—	—	—
Illinois	1,455,652	1.02%	18.30	0.33%	1,318,916	0.99%	29.30	0.52%
Indiana	615,018	0.59%	—	—	—	—	6.30	0.34%
Iowa	481,271	1.05%	9.09	0.89%	491,543	1.06%	7.92	0.78%
Kansas	8,907	0.02%	—	—	—	—	—	—
Kentucky	401,864	0.45%	2.03	0.27%	437,276	0.52%	2.96	0.39%
Louisiana	20,572.422	0.02%	—	—	—	—	—	—
Maine	136,985	1.19%	0.02	0.02%	92,313	0.78%	0.14	0.15%
Maryland	539,640	0.87%	1.30	0.09%	641,322	0.97%	1.00	0.07%
Massachusetts	980,113	1.80%	22.63	1.17%	1,116,442	2.05%	24.67	1.28%
Michigan	1,198,644	1.15%	43.80	1.02%	1,284,863	1.51%	44.00	1.02%
Minnesota	662,687.1	0.98%	25.83	1.31%	699,998	1.04%	26.82	1.36%
Mississippi	36,810	0.08%	—	—	—	—	—	—
Missouri	100,644	0.12%	—	—	406,897	0.49%	—	—
Montana	91,474	0.66%	—	—	—	—	—	—
Nebraska	86,527	0.29%	—	—	53,850	0.20%	—	—
Nevada	188,757	0.54%	—	—	171,369	0.81%	0.96	0.14%
New Hampshire	57,938	0.53%	1.95	1.31%	58,774	0.56%	1.39	0.93%
New Jersey	414,794	0.55%	—	—	418,693	0.56%	8.82	0.24%
New Mexico	126,195	0.54%	0.62	0.11%	126,069	0.54%	0.68	0.12%
New York	1,338,060	0.94%	18.83	0.29%	1,617,667	1.13%	25.70	0.40%
North Carolina	533,404	0.42%	—	—	718,739	0.55%	—	—

State	2012 electric program savings (MWh)	Savings as % of retail sales	2012 natural gas program savings (MMTherms)	Savings as % of retail sales*	2013 electric program savings (MWh)	Savings as % of retail sales	2013 natural gas program savings (MMTherms)	Savings as % of retail sales*
North Dakota	10,330	0.07%	—	—	—	—	—	—
Ohio	1,323,498	0.87%	—	—	—	—	—	—
Oklahoma	99,198	0.17%	1.50	0.17%	156,847	0.27%	2.90	0.33%
Oregon	510,993	1.10%	5.59	0.77%	676,046	1.43%	5.30	0.73%
Pennsylvania	1,533,976	1.06%	—	—	1,410,305	0.97%	—	—
Puerto Rico	—	—	—	—	—	—	—	—
Rhode Island	119,666	1.55%	2.30	0.86%	161,831	2.09%	3.30	1.24%
South Carolina	273,758	0.35%	0.07	0.02%	298,215	0.38%	0.08	0.02%
South Dakota	29,475	0.25%	0.20	0.10%	21,435	0.18%	0.43	0.21%
Tennessee	302,493	0.31%	0.00	0.00%	273,267	0.28%	0.00	0.00%
Texas	686,554	0.19%	0.00	0.00%	693,968	0.19%	0.00	0.00%
Utah	219,612	0.74%	4.10	0.42%	264,375	0.87%	6.37	0.65%
Vermont	117,649	2.14%	0.75	1.37%	99,074	1.78%	0.80	1.47%
Virgin Islands	—	—	—	—	—	—	—	—
Virginia	29,923	0.03%	—	—	—	—	—	—
Washington	856,137	0.92%	5.94	0.44%	990,143	1.35%	7.02	0.51%
West Virginia	54,105	0.18%	0.59	0.13%	69,241	0.22%	0.70	0.15%
Wisconsin	460,784	0.67%	16.50	0.85%	619,418	0.90%	17.50	0.90%
Wyoming	23,605	0.14%	—	—	—	—	—	—

Savings are net savings. We applied a 0.9 net-to-gross ratio where only gross savings were available. *Natural gas sales are 2012 commercial and retail sales only from EIA (2014b).

Table 13. 2014 net incremental electricity savings by state

State	2014 net incremental savings (MWh)	% of 2014 retail sales	Score (6 pts.)
Rhode Island	268,468	3.51%	6
Massachusetts	1,339,026	2.50%	6
Vermont	102,770	1.85%	5.5
California ǂ	4,082,256	1.58%	4.5
Arizona	1,190,123	1.57%	4.5
Hawaii	144,240	1.53%	4.5
Michigan	1,386,912	1.35%	4
Connecticut	387,863	1.32%	3.5
Maryland	792,354	1.29%	3.5
Oregon	595,548	1.27%	3.5
Minnesota ǂ	824,756	1.22%	3.5
Maine	145,413	1.21%	3.5
Iowa	550,035	1.17%	3.5
Illinois	1,513,045	1.08%	3
Ohio*	1,565,049	1.05%	3
Washington ǂ	946,565	1.02%	3
New York	1,338,551	0.92%	2.5
Colorado[1]	472,000	0.88%	2.5
Wisconsin	527,283	0.76%	2
Indiana[2]	768,927	0.74%	2
Utah	213,468	0.71%	2
Idaho	159,310	0.81%	2
New Jersey ǂ	500,784	0.68%	2
Montana*	92.923	0.66%	1.5
North Carolina	854,582	0.64%	1.5
Pennsylvania ǂ	866,721	0.59%	1.5
Nevada	194,861	0.57%	1.5
New Hampshire ǂ	61,046	0.56%	1.5
District of Columbia	60,879	0.54%	1.5
New Mexico	123,919	0.54%	1.5
South Carolina	435,399	0.53%	1.5
Arkansas	249,303	0.53%	1.5
Missouri ǂ	431,218	0.52%	1.5
Kentucky	286,272	0.37%	1
Oklahoma	180,032	0.30%	0.5
Tennessee	292,100	0.30%	0.5
Georgia	316,394	0.23%	0.5
West Virginia	74,339	0.23%	0.5
Nebraska	67,878	0.23%	0.5
South Dakota	26,056	0.21%	0.5
Texas[3]	728,047	0.19%	0.5
Wyoming*	29,571	0.17%	0.5
Mississippi	75,815	0.15%	0
Florida[4]	329,000	0.15%	0
Alabama	56,045	0.06%	0
Delaware ǂ	4,415	0.04%	0
Alaska*	2,138	0.03%	0
Virginia*	26,233	0.02%	0
Louisiana[5]	19,215	0.02%	0
North Dakota*	2,567	0.02%	0
Kansas*	2,224	0.01%	0
Guam	0	0.00%	0
Puerto Rico	0	0.00%	0
Virgin Islands	0	0.00%	0
US total	**25,734,569**	**0.69%**	
Median	**258,886**	**0.56%**	

Savings data are from public service commission staff as listed in Appendix A unless noted otherwise. Sales data are from EIA 2015b. *For these states, we did not have 2014 savings data, so we scored them on 2013 savings as reported in EIA 2015a unless otherwise noted. ǂ At least a portion of savings reported as gross. The gross portion has been adjusted by a net-to-gross factor of 0.9 to make it more comparable with net savings figures reported by other states. [1] 2013 savings as reported in CO data request. [2] MEEA. [3] SPEER. [4] 2013 savings as reported in FL data request. [5] Entergy New Orleans 2014.

Table 9. 2015 net incremental electricity savings by state

State	2015 net incremental savings (MWh)	% of 2015 retail sales	Score (7 pts.)
Rhode Island	222,822	2.91%	7
Massachusetts	1,472,536	2.74%	7
Vermont	110,642	2.01%	7
California†	5,040,603	1.95%	6.5
Maine†	183,347	1.53%	5
Hawaii[1]	144,240	1.52%	5
Connecticut	435,740	1.48%	5
Washington	1,275,447	1.42%	4.5
Arizona†	918,582	1.19%	4
Michigan	1,177,277	1.16%	3.5
Minnesota†	750,672	1.15%	3.5
Illinois	1,553,917	1.13%	3.5
Oregon†	507,502	1.09%	3.5
New York	1,559,665	1.05%	3.5
Maryland	621,090	1.01%	3
Iowa	469,483	1.00%	3
Ohio*†	1,353,109	0.92%	3
Colorado	486,215	0.90%	3
Utah	254,153	0.85%	2.5
Wisconsin	538,678	0.79%	2.5
Indiana[2]	768,927	0.76%	2.5
Nevada†	257,034	0.72%	2
Idaho[3]	159,310	0.69%	2
Montana[4]	92,923	0.66%	2
Pennsylvania*	904,238	0.64%	2
North Carolina	827,508	0.62%	2
Missouri†	494,013	0.61%	2
District of Columbia	69,247	0.61%	2
Arkansas	282,000	0.61%	2
New Hampshire†	64,869	0.59%	1.5
New Mexico	128,834	0.56%	1.5
New Jersey†	409,957	0.55%	1.5
South Carolina[5]	435,399	0.54%	1.5
Nebraska*	156,473	0.53%	1.5
Kentucky	266,522	0.36%	1
Oklahoma	190,497	0.32%	1
Mississippi	144,401	0.29%	0.5
South Dakota	28,686	0.24%	0.5
Georgia†	315,625	0.23%	0.5
Tennessee†	185,355	0.19%	0.5
West Virginia	61,349	0.19%	0.5
Delaware†	21,624	0.19%	0.5
Texas†	698,688	0.18%	0.5
Florida*†	262,085	0.11%	0
Wyoming*†	15,515	0.09%	0
Alabama*†	78,067	0.09%	0
Louisiana	66,695	0.08%	0
Virginia*†	71,182	0.06%	0
North Dakota†	1,663	0.01%	0
Alaska*†	409	0.01%	0
Kansas*†	774	0.00%	0
Guam	—	0.00%	0
Puerto Rico	—	—	0
Virgin Islands	—	0.00%	0
US total	**26,535,588**	**0.71%**	
Median	**255,593**	**0.61%**	

Savings data are from public service commission staff as listed in Appendix A unless noted otherwise. Sales data are from EIA Form 826 (2016c). * For these states, we did not have 2015 savings data, so we scored them on 2014 savings as reported in EIA Form 861 (2016b), unless otherwise noted. [1] 2014 savings as reported in Hawaii data request. [2] 2014 savings as reported in Indiana data request. [3] 2014 savings as reported in Idaho data request. [4] 2014 savings as reported in Montana data request. [5] 2014 savings as reported in South Carolina data request. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.817 to make it comparable with net savings figures reported by other states.

Table 9. 2016 net incremental electricity savings by state

State	2016 net incremental savings (MWh)	% of 2016 retail sales	Score (6 pts.)	State	2016 net incremental savings (MWh)	% of 2016 retail sales	Score (6 pts.)
Massachusetts	1,569,661	3.00%	7	Kentucky†	344,151	0.47%	1.5
Rhode Island	214,329	2.85%	7	New Jersey†	332,659	0.44%	1
Vermont	138,318	2.52%	7	Indiana†	424,127	0.42%	1
Washington†	1,358,095	1.54%	5	Oklahoma	236,027	0.39%	1
California†	3,909,215	1.54%	5	Missouri	301,909	0.39%	1
Connecticut	442,250	1.53%	5	South Carolina*†	304,919	0.38%	1
Arizona	1,108,273	1.42%	4.5	Montana†	52,593	0.38%	1
Maine†	157,921	1.38%	4.5	South Dakota†	35,708	0.30%	0.5
Hawaii*†	124,399	1.32%	4.5	Wyoming	47,057	0.28%	0.5
Minnesota†	847,830	1.31%	4.5	Georgia†	379,294	0.27%	0.5
Illinois	1,716,876	1.23%	4	Mississippi	126,027	0.26%	0.5
Michigan	1,209,981	1.17%	4	Tennessee†	189,930	0.19%	0.5
Oregon†	537,331	1.16%	4	Nebraska†	56,275	0.19%	0.5
Idaho†	258,598	1.13%	3.5	Texas[2]†	740,430	0.19%	0.5
New York	1,599,900	1.09%	3.5	West Virginia	57,925	0.18%	0.5
Iowa†[1]	482,316	1.01%	3	Florida†	263,116	0.11%	0
Maryland	560,617	0.91%	3	Louisiana†	87,023	0.10%	0
Colorado	487,396	0.89%	3	Virginia*†	99,557	0.09%	0
Ohio	1,284,472	0.87%	2.5	Alabama*†	49,988	0.06%	0
Utah	232,299	0.78%	2.5	Delaware†	1,367	0.01%	0
Pennsylvania	1,058,768	0.73%	2	North Dakota†[3]	1,761	0.01%	0
Arkansas	310,815	0.68%	2	Alaska*†	346	0.01%	0
District of Columbia	73,811	0.65%	2	Kansas*†	440	0.00%	0
Nevada†	227,348	0.63%	2	Guam	–	0.00%	0
Wisconsin	424,177	0.61%	2	Puerto Rico	–	0.00%	0
New Mexico	135,000	0.59%	1.5	Virgin Islands	–	0.00%	0
New Hampshire†	63,338	0.58%	1.5	**US total**	**25,417,008**	**0.68%**	
North Carolina†	759,029	0.57%	1.5	**Median**	**247,313**	**0.59%**	

Savings data are from public service commission staff as listed in Appendix A, unless noted otherwise. Sales data are from EIA Form 861M (2017b). * For these states, we did not have 2016 savings data, so we scored them on 2015 savings as reported in EIA Form 861 (2017a), unless otherwise noted. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.866 to make it comparable to net savings figures reported by other states. [1] 2016 savings reported for MidAmerican Energy and Interstate Power & Light; 2015 savings reported for municipal utilities and rural electric cooperatives. [2] Texas savings are from 2016, except for 2015 savings reported for CPS Energy and Energy Austin. [3] 2015 savings as reported in North Dakota data request.

Table 8. 2017 net incremental electricity savings by state

State	2017 net incremental savings (MWh)	% of 2016 retail sales	Score (7 pts.)
Vermont	183,722	3.33%	7
Rhode Island	232,032	3.08%	7
Massachusetts	1,374,066	2.57%	7
California†	5,062,747	1.97%	6.5
Connecticut	469,822	1.62%	5.5
Michigan	1,545,158	1.48%	5
Hawaii†	136,847	1.45%	5
Washington†	1,195,606	1.35%	4.5
Illinois	1,885,000	1.34%	4.5
Arizona†	1,040,031	1.33%	4.5
Minnesota†	868,973	1.31%	4.5
Oregon†	574,167	1.21%	4
New York	1,722,962	1.17%	4
Maryland	594,234	0.97%	3
Idaho†	222,307	0.96%	3
Ohio†	1,448,198	0.96%	3
Colorado	483,500	0.88%	3
Iowa†	421,963	0.87%	2.5
Maine†	97,322	0.85%	2.5
Utah	254,907	0.84%	2.5
Missouri	615,564	0.78%	2.5
District of Columbia	85,613	0.75%	2.5
New Hampshire†	77,740	0.71%	2
Arkansas	319,788	0.69%	2
North Carolina†	928,922	0.69%	2
Wisconsin	460,743	0.66%	2
Nevada†	217,014	0.60%	2
Pennsylvania	797,448	0.55%	1.5
New Jersey	413,344	0.55%	1.5
New Mexico	120,404	0.52%	1.5
Montana†	71,689	0.51%	1.5
Kentucky†	311,552	0.42%	1
Oklahoma	254,425	0.41%	1
Indiana*†	424,127	0.41%	1
South Carolina*†	304,919	0.38%	1
Wyoming†	46,274	0.28%	0.5
Nebraska†	75,953	0.25%	0.5
South Dakota	29,937	0.25%	0.5
Georgia†	328,147	0.24%	0.5
West Virginia	69,770	0.22%	0.5
Mississippi†	99,873	0.20%	0.5
Texas†	800,893	0.20%	0.5
Tennessee*	189,930	0.19%	0.5
Delaware	12,564	0.11%	0
Virginia*†	99,557	0.09%	0
Florida†	207,106	0.09%	0
Alabama*	49,988	0.06%	0
Louisiana	45,514	0.05%	0
North Dakota*†	1,761	0.01%	0
Alaska*	346	0.01%	0
Kansas*†	440	0.00%	0
US total	**27,274,908**	**0.72%**	
Median	**254,907**	**0.66%**	

Savings data are from public service commission staff as listed in Appendix A, unless noted otherwise. Sales data are from EIA Form 861M (2017b).
* States for which we did not have 2017 savings data were scored on 2016 state-reported savings or EIA-reported 2016 savings. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.856 to make it comparable with net savings figures reported by other states.

EXHIBIT TW/EM – 34

SELECTIONS FROM ACEEE SCORECARDS FROM 2013-2018, SPENDING AS PERCENT OF REVENUE

Table 11. 2012 Electric Efficiency Program Budgets by State

State	2012 Budget ($million)	% of Statewide Utility Revenues	Score (5 pts.)
Rhode Island	61.4	7.61%	5
Massachusetts[1]	515.7	6.78%	5
Washington[2]	344.8	5.37%	5
Vermont[3]	39.3	5.20%	5
Oregon[4]	153.0	3.98%	4.5
California	1166.6	3.28%	4
New Jersey[5]	329.4	3.16%	3.5
New York[6]	668.9	3.09%	3.5
Connecticut[7]	128.1	2.79%	3
Minnesota[8]	156.0	2.60%	3
Iowa[9]	90.6	2.56%	3
Idaho	38.7	2.39%	2.5
Maryland[10]	139.2	1.99%	2
Montana[11]	21.0	1.84%	2
Pennsylvania	257.0	1.80%	2
Illinois	208.6	1.72%	2
Maine[12]	23.4	1.71%	2
Arizona	124.0	1.69%	2
Colorado[13]	81.4	1.62%	2
Utah	36.1	1.55%	1.5
New Hampshire[14]	22.9	1.48%	1.5
Michigan[15]	169.2	1.47%	1.5
Ohio	200.7	1.45%	1.5
Arkansas[16]	50.3	1.42%	1.5
Nevada[17]	42.0	1.34%	1.5
Hawaii[18]	35.6	1.09%	1
Wisconsin[19]	78.7	1.08%	1
New Mexico[20]	19.7	0.96%	1
District of Columbia[21]	12.2	0.92%	1
Florida	200.0	0.87%	1
Oklahoma	34.1	0.77%	0.5
Indiana	62.7	0.73%	0.5
Nebraska[22]	17.5	0.70%	0.5
Tennessee	58.2	0.65%	0.5
South Carolina[23]	40.5	0.58%	0.5
Kentucky	36.4	0.57%	0.5
North Carolina	61.7	0.53%	0.5
Wyoming[24]	6.0	0.49%	0.5
South Dakota[25]	4.8	0.48%	0.5
Texas	144.4	0.46%	0.5
West Virginia	9.9	0.40%	0.5
Missouri	26.3	0.38%	0
Kansas[26]	12.3	0.33%	0
Delaware[27]	3.8	0.30%	0
Mississippi	11.9	0.29%	0
Georgia	29.9	0.25%	0
Alabama	10.1	0.13%	0
Louisiana	3.7	0.06%	0
Virginia	0.2	0.00%	0
Alaska	0.0	0.00%	0
North Dakota	0.0	0.00%	0
US Total	5988.9	1.63%	
Median	40.5	1.09%	

Sources & notes: Budget data are from CEE (2013) except where noted. Statewide revenue data are from EIA (2013a). [1]MA DOER (2013); [2]Includes share of budget based on 2011 allocation of BPA incentive dollars across states (2013); [3]VEIC (2013); [4]Energy Trust of Oregon (2013), includes share of budget from BPA incentive dollars (2013); [5]AEG (2013); [6]Includes NYSERDA (2013), NY DPS (2013), and LIPA (2013); [7]CT DEEP (2013); [8]MN DOC (2013); [9]Includes share of budget from BPA incentive dollars(2013); [10]MD PSC (2013); [11]Includes share of budget from BPA incentive dollars (2013); [12]Efficiency Maine (2013); [13]CO PUC (2013); [14]NH PUC (2013); [15]MI PSC (2013); [16]AR PSC (2013); [17]NV PUCN (2013), BPA (2013); [18]Jim Flanagan Associates (2013); [19]Actual spending from WI PSC (2013); [20]NM PRC (2013); [21]Actual spending from DDOE (2013); [22]NE NEO (2013); [23]Actual spending from SC ORS (2013); [24]Includes share of budget from BPA incentive dollars; [25]SD PUC (2013); [26]KCC (2013); [27]DNREC (2013)

Table 10. 2013 electric efficiency program budgets by state

State	2013 budget ($million)	% of statewide utility revenues	Score (5 pts.)
Rhode Island[1]	77.5	8.55%	5
Massachusetts[2]	507.7	6.42%	5
Vermont[3]	42.8	5.32%	5
Washington[4]	293.7	4.60%	5
Oregon[5]	171.3	4.32%	5
New Jersey	395.1	3.88%	4.5
Connecticut[6]	102.4	3.28%	4
California[7]	1188.8	3.18%	3.5
Maryland[8]	205.9	2.85%	3.5
Iowa[9]	106.7	2.83%	3.5
New York	593.9	2.65%	3
Illinois[10]	283.8	2.51%	3
Maine[11]	34.2	2.43%	3
Minnesota[12]	155.5	2.42%	3
New Hampshire[13]	27.4	2.24%	2.5
Idaho[14]	38.8	2.12%	2.5
Arizona[15]	143.2	1.86%	2
Arkansas[16]	65.9	1.81%	2
Colorado[17]	89.4	1.69%	2
Pennsylvania	237.6	1.66%	2
Nevada[18]	50.5	1.59%	1.5
Ohio	212.8	1.56%	1.5
Montana[19]	18.4	1.53%	1.5
Michigan[20]	165.5	1.43%	1.5
Utah	35.3	1.42%	1.5
Florida	258.1	1.13%	1
Wisconsin	79.9	1.09%	1
New Mexico[21]	23.1	1.08%	1
District of Columbia	14.0	1.06%	1
Hawaii	33.5	1.06%	1
Indiana[22]	76.8	0.86%	1
Oklahoma[23]	38.7	0.84%	1
Tennessee[24]	55.7	0.81%	1
Kentucky[25]	44.0	0.70%	0.5
Missouri	48.2	0.65%	0.5
North Carolina[26]	74.9	0.63%	0.5
Texas	181.4	0.56%	0.5
Nebraska[27]	13.8	0.53%	0.5
Wyoming	6.4	0.50%	0.5
South Dakota[28]	5.1	0.48%	0.5
West Virginia[29]	9.0	0.37%	0
Georgia[30]	40.1	0.32%	0
South Carolina	22.1	0.31%	0
Delaware[31]	2.4	0.19%	0
Mississippi	7.5	0.17%	0
Alabama	10.8	0.14%	0
Louisiana	3.7	0.05%	0
Kansas	0.7	0.02%	0
Virginia	0.8	0.01%	0
Alaska	0.0	0.00%	0
Guam[32]	0.0	0.00%	0
North Dakota	0.0	0.00%	0
Puerto Rico[33]	0.0	0.00%	0
Virgin Islands[34]	0.0	0.00%	0
U.S. total	6294.6	-	
Median	43.4	1.09%	

Budget data are from CEE 2014 except where noted. Statewide revenue data are from EIA 2014a. [1]RI PUC 2014.[2]MA DOER 2014.[3]VT PSD 2014.[4]Includes share of budget-based allocation of Bonneville Power Administration(BPA) incentive dollars across states.[5]Energy Trust of Oregon 2014 and2014; includes share of budget from BPA incentive dollars.[6]CT DEEP 2014.[7]CPUC 2014.[8]MD PSC 2014.[9]IUB 2014.[10]ICC 2014.[11]Efficiency Maine 2014.[12] MN COMM 2014.[13]NH PUC 2014.[14]Includes share of budget from BPA incentive dollars.[15]SWEEP 2014a.[16]AR PSC 2014.[17]CO DORA 2014.[18]NV PUCN 2014; includes share of budget from BPA incentive dollars.[19]Includes share of budget from BPA incentive dollars.[20]MI PSC 2014.[21]NM PRC 2014.[22]IURC 2014.[23]OCC 2014.[24]TVA 2014.[25]KY PSC 2014.[26]PSNCUC 2014.[27]NPPD 2014; OPPD 2014; Lincoln Electric System 2014.[28]SD PUC 2014.[29]WV PSC 2014.[30]GA PSC 2014.[31]DNREC 2014.[32]Guam Energy Office 2014.[33]Puerto Rico Office of the Governor 2014. [34]Virgin Islands Energy Office 2014.

Table 9. 2014 electric efficiency program spending by state

State	2014 spending ($million)	% of statewide electricity revenues	Score (4 pts.)
Rhode Island	81.1	6.81%	4
Massachusetts	503.8	6.14%	4
Vermont	48.1	5.95%	4
Maryland	319.3	4.27%	4
Washington	279.5	4.22%	4
Oregon	159.8	3.88%	3.5
Connecticut	180.6	3.62%	3.5
California	1237.6	3.14%	3
Iowa	108.5	2.80%	2.5
Utah	57.2	2.27%	2
Illinois	265.1	2.13%	2
Minnesota[1]	135.6	2.09%	2
New Jersey	201.5	1.96%	1.5
Arkansas	72.2	1.95%	1.5
Colorado	95.1	1.77%	1.5
Idaho[2]	31.7	1.72%	1.5
New Hampshire	28.3	1.69%	1.5
Michigan	178.2	1.56%	1.5
Arizona	120.1	1.54%	1.5
Oklahoma	71.9	1.48%	1
Nevada	49.2	1.46%	1
Maine	22.0	1.45%	1
New York	314.0	1.33%	1
Pennsylvania	197.6	1.31%	1
Montana[3]	15.5	1.28%	1
Indiana	111.7	1.20%	1
New Mexico	24.9	1.12%	1
Hawaii	33.3	1.06%	1
Wisconsin	75.0	1.01%	1
District of Columbia	13.5	0.99%	0.5
Missouri	67.0	0.90%	0.5
North Carolina	106.6	0.86%	0.5
Florida	202.8	0.83%	0.5
Kentucky	39.5	0.63%	0.5
Ohio*	86.4	0.60%	0.5
Texas	201.3	0.59%	0.5
Tennessee	51.9	0.56%	0.5
South Carolina	36.5	0.47%	0
South Dakota	4.9	0.44%	0
West Virginia	11.0	0.44%	0
Wyoming[4]	5.3	0.40%	0
Nebraska	8.9	0.34%	0
Georgia	36.3	0.27%	0
Alabama*	15.1	0.18%	0
Mississippi	8.1	0.17%	0
Delaware	1.9	0.15%	0
North Dakota*	0.7	0.05%	0
Louisiana	2.2	0.03%	0
Kansas*	0.9	0.02%	0
Virginia*	0.8	0.01%	0
Alaska*	0.0	0.00%	0
Guam	0.0	0.00%	0
Puerto Rico	0.0	0.00%	0
Virgin Islands	0.0	0.00%	0
US total	**5,919.8**	-	
Median	**50.5**	**1.09%**	

Spending data are from public service commission staff as listed in Appendix A. * Where 2014 spending was not available, we substituted 2013 spending as reported by CEE 2015, except where noted. [1] 2013 actual spending as reported in MN data request. [2] 2013 actual spending from CEE 2015, includes share of BPA electric spending. [3] 2013 actual spending as reported by EIA 2015a. [4] 2013 actual spending from CEE 2015, includes share of BPA electric spending.

In this category, we scored states on 2014 electricity energy efficiency program spending for customer-funded energy efficiency programs. These are funded through charges included in utility customers' rates or as a line item on customer bills. This includes spending by investor-owned, municipal, and cooperative utilities, public power companies or

Table 13. 2015 electric efficiency program spending by state

State	2015 spending ($million)	% of statewide electricity revenues	Score (3 pts.)
Vermont	54.4	6.89%	3
Rhode Island	82.9	6.34%	3
Massachusetts	557.9	6.16%	3
Washington	256.9	3.87%	2.5
Maryland	276.8	3.69%	2.5
Oregon	142.9	3.45%	2.5
California	1378.2	3.43%	2.5
Connecticut	173.9	3.32%	2.5
Iowa	113.3	2.86%	2
Maine	42.5	2.74%	2
Minnesota	151.5	2.40%	1.5
Illinois	286.4	2.24%	1.5
Utah	55.9	2.17%	1.5
Arkansas	76.1	2.01%	1.5
Idaho[1]	32.7	1.75%	1
Michigan	188.0	1.70%	1
New Jersey	177.6	1.70%	1
New York	375.7	1.66%	1
Colorado	87.6	1.65%	1
New Mexico	34.3	1.54%	1
Oklahoma	70.2	1.50%	1
New Hampshire	25.6	1.45%	0.5
Pennsylvania	217.2	1.43%	0.5
Missouri	102.3	1.37%	0.5
Hawaii*	33.3	1.34%	0.5
Nevada	45.4	1.34%	0.5
Arizona	105.0	1.31%	0.5
Indiana*	111.7	1.26%	0.5
Ohio[2]	171.9	1.18%	0.5
Wisconsin	79.8	1.07%	0.5
District of Columbia	13.9	1.01%	0.5
North Carolina	113.7	0.91%	0
Florida*	218.0	0.88%	0
Kentucky	43.2	0.72%	0
Montana	9.0	0.72%	0
Texas[3]	181.7	0.54%	0
Tennessee	48.0	0.53%	0
Nebraska	12.9	0.49%	0
South Carolina	36.5	0.47%	0
South Dakota	5.3	0.47%	0
West Virginia	12.4	0.47%	0
Wyoming[4]	5.1	0.38%	0
Mississippi	17.2	0.37%	0
Georgia	41.5	0.32%	0
Delaware	4.0	0.31%	0
Louisiana	13.4	0.20%	0
Alabama[5]	12.2	0.15%	0
North Dakota	0.3	0.02%	0
Virginia[6]	0.1	0.00%	0
Alaska	0.0	0.00%	0
Guam	0.0	0.00%	0
Kansas[7]	0.0	0.00%	0
Puerto Rico	0.0	0.00%	0
Virgin Islands	0.0	0.00%	0
US total	**6,296.4**	-	
Median	**51.2**	**1.28%**	

Statewide revenues are from EIA Form 826 (EIA 2016c). Spending data are from public service commission staff as listed in Appendix A. * Where 2015 spending was not available, we substituted 2014 spending as reported by states, except where noted. [1] 2014 actual spending from CEE 2016 and 2015 BPA spending. [2] 2014 actual spending from CEE 2016. [3] 2015 spending, except for 2014 spending data for CPS Energy and Energy Austin. [4] 2014 actual spending from CEE 2016. [5] 2014 actual spending from CEE 2016. [6] 2014 actual spending from CEE 2016. [7] 2014 actual spending from CEE 2016.

Table 13. 2016 electric efficiency program spending by state

State	2016 spending ($million)	% of statewide electricity revenues	Score (2.5 pts.)
Vermont	54.0	6.84%	2.5
Rhode Island	78.4	6.42%	2.5
Massachusetts	538.9	6.25%	2.5
Washington	291.2	4.29%	2
Connecticut	191.9	3.85%	1.5
Oregon	156.6	3.79%	1.5
California	1,364.1	3.50%	1.5
Iowa	119.2	2.86%	1
Idaho	49.8	2.67%	1
Minnesota	161.9	2.50%	1
Maryland	186.8	2.49%	1
Maine	32.3	2.21%	1
Utah	55.1	2.11%	1
Illinois	262.8	2.05%	1
New York	425.2	2.00%	1
Arkansas	68.7	1.86%	1
Hawaii[1]	37.0	1.64%	0.5
Colorado	87.2	1.63%	0.5
New Mexico*	34.3	1.62%	0.5
Nevada	49.0	1.62%	0.5
Michigan	182.1	1.58%	0.5
Arizona	126.7	1.56%	0.5
Pennsylvania	229.4	1.55%	0.5
New Jersey	154.0	1.53%	0.5
Oklahoma*	70.2	1.50%	0.5
New Hampshire	23.2	1.36%	0.5
Kentucky	72.9	1.21%	0.5
Missouri	88.4	1.20%	0.5
North Carolina	144.6	1.17%	0.5
Montana	13.5	1.09%	0.5
Ohio	141.0	0.98%	0.5
Wisconsin	74.1	0.98%	0.5
Indiana	87.0	0.97%	0.5
District of Columbia	13.0	0.96%	0.5
Florida	178.1	0.76%	0
Wyoming	10.1	0.74%	0
Texas[2]	194.1	0.60%	0
Tennessee	52.5	0.58%	0
South Dakota	5.8	0.49%	0
Georgia	57.9	0.45%	0
West Virginia	12.3	0.43%	0
Delaware*	5.3	0.43%	0
Nebraska	11.6	0.43%	0
Mississippi	17.2	0.40%	0
South Carolina[3]	29.8	0.39%	0
Louisiana[4]	17.0	0.26%	0
Alabama[5]	16.2	0.19%	0
Virginia	0.1	0.00%	0
Alaska	0.0	0.00%	0
Guam	0.0	0.00%	0
Kansas	0.0	0.00%	0
North Dakota	0.0	0.00%	0
Puerto Rico	0.0	0.00%	0
Virgin Islands	0.0	0.00%	0
US total	**6,272.6**	**-**	
Median	**56.5**	**1.20%**	

Statewide revenues are from EIA Form 861-M (EIA 2017c). Spending data are from public service commission staff as listed in Appendix A. * Where 2016 spending was not available, we substituted 2015 spending as reported by states, except where noted. [1] 2015 spending from CEE 2017. [2] 2016 spending, except for 2015 spending from CPS Energy and Energy Austin. [3] 2015 spending from CEE 2017. [4] 2016 spending, except for 2015 spending from Entergy New Orleans. [5] 2015 spending from CEE 2017.

Table 12. 2017 electric efficiency program spending by state

State	2017 elec. spending ($ million)	% of statewide elec. revenues	Score (2.5 pts.)
Vermont	64.0	8.02%	2.5
Massachusetts	620.6	7.04%	2.5
Rhode Island	83.4	6.81%	2.5
Washington	281.8	4.13%	2
Oregon	158.6	3.79%	1.5
California	1,412.1	3.61%	1.5
Idaho	64.6	3.46%	1.5
Connecticut	153.9	3.08%	1.5
Iowa	112.3	2.71%	1
Maryland	201.5	2.69%	1
Illinois	349.1	2.64%	1
Minnesota	165.0	2.48%	1
Maine	31.1	2.12%	1
New York	450.1	2.10%	1
Utah	51.4	1.95%	1
Michigan	220.4	1.91%	1
New Mexico	38.7	1.84%	0.5
Arkansas	68.6	1.83%	0.5
Colorado	96.2	1.79%	0.5
Nevada	51.0	1.68%	0.5
New Hampshire	26.1	1.53%	0.5
North Carolina	180.9	1.46%	0.5
Delaware	18.2	1.45%	0.5
Arizona	105.0	1.31%	0.5
Oklahoma	66.0	1.37%	0.5
Kentucky	84.7	1.35%	0.5
Missouri	100.0	1.31%	0.5
Ohio	186.9	1.26%	0.5
New Jersey	113.5	1.13%	0.5
Pennsylvania	164.1	1.11%	0.5
District of Columbia	13.9	1.04%	0.5
Montana	13.0	1.04%	0.5
Wisconsin	70.6	0.95%	0.5
Hawaii	20.8	0.92%	0.5
Indiana*	87.0	0.91%	0.5
Florida	190.3	0.82%	0.5
Wyoming	10.5	0.77%	0
Texas	257.7	0.77%	0
Mississippi	27.6	0.65%	0
Tennessee	59.6	0.64%	0
South Carolina*	43.1	0.55%	0
West Virginia	14.2	0.49%	0
Georgia	55.5	0.42%	0
Nebraska	10.2	0.37%	0
South Dakota	4.4	0.37%	0
Alabama*	16.2	0.19%	0
Louisiana	7.3	0.11%	0
Virginia*	0.5	0.00%	0
Alaska*	—	0.00%	0
Kansas*	—	0.00%	0
North Dakota*	—	0.00%	0
US Total	**6,632.4**	**1.72%**	
Median	**66.0**	**1.35%**	

Statewide revenues are from EIA Form 826 (EIA 2018c). Spending data are from public service commission staff as listed in Appendix A.
* Where 2017 spending was not available, we substituted 2016 spending as reported by states.

EXHIBIT TW/EM – 35

RESPONSE TO SIERRA CLUB 4-8

Virginia Electric and Power Company
Case No. PUR-2018-00168
Sierra Club
Fourth Set

The following response to Question No. 8 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Elizabeth Lecky
Regulatory Specialist
Dominion Energy Services, Inc.

The following response to Question No. 8 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Sierra Club received on January 22, 2019 has been prepared under my supervision.

Lisa R. Crabtree for
Jarvis E. Bates
Energy Conservation Compliance Consultant
Dominion Energy Virginia

Question No. 8

Please provide the Company's spending on DSM as a percent of the Company's total revenue for each year from 2012 through 2017.

Response:

See below for the Company's spending on DSM (EE programs) as a percent of the Company's total revenue (per the Virginia Electric and Power Company FERC Form 1 Total Electric Operating Revenues) for each year from 2012 through 2017.

2012	2013	2014	2015	2016	2017
0.17%	0.20%	0.48%	0.45%	0.55%	0.38%

CERTIFICATE OF SERVICE

I hereby certify that, on **February 6, 2019,** I deposited true copies of the foregoing into the United States mail, postage prepaid and addressed to the following:

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