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Development and Application of Select Non-Energy Benefits for the EmPOWER Maryland Energy Efficiency Programs

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Introduction

The EmPOWER Maryland programs have been thoroughly evaluated and subjected to cost effectiveness testing throughout their five-year history. While other cost effectiveness screening tests have been reported, the Public Service Commission's cost effectiveness determination has generally focused on the Total Resource Cost (TRC) benefit cost test. The TRC is estimated at the program level, but, at least to date, the Commission has required only that sector level portfolios of each utility be cost effective.

To accurately reflect the net impacts of programs on utilities and utility customers, the TRC should capture and compare the present value of all participant, non-participant and utility benefits to the present value of all participant, non-participant and utility costs. In practice, the TRC analyses, in Maryland and elsewhere, more fully capture the costs associated with the programs than the benefits. A long list of non-energy benefits are usually omitted from energy efficiency program TRC analyses.

The EMPOWER programs ex post cost effectiveness analyses have included a few non-energy impacts, some of which improve and some of which diminish the cost effectiveness.[1] For example, the 2012 and 2013 analyses included:

- Incandescent lamp replacement costs for residential lighting measures – these increase the TRC benefits.
- Water and sewer bill reductions – these increase the TRC benefits.
- Reduction in natural gas and other heating fuel costs – these increase the TRC benefits.
- Increased natural gas costs resulting from reductions in waste heat from improved lighting efficiency -- these decrease the TRC benefits.

Among these benefits, only natural gas benefits have been included in previous ex ante cost effectiveness analyses used to develop the utilities' EmPOWER 3-year program plans. A 1.115 cent per kWh adder has been applied to the ex ante societal cost test (SCT) by four of the

[1] Itron conducted these analyses for the years 2009 through 2012 and has transferred the analysis over to Navigant starting with 2013. Henceforth, Itron will review and verify the cost effectiveness analyses as is done for the annual ex post evaluations.

EmPOWER utilities, but the SCT has to date received little attention from the Commission in its consideration of program or portfolio cost effectiveness.

The Commission and some stakeholders have been reluctant to expand the list of non energy benefits that are included in the TRC analyses. The overarching concern is that adding these benefits to the TRC will undermine its credibility with some stakeholders. This reluctance is primarily driven by the uncertainty associated with the estimating various non energy impacts. Some utilities have also expressed concern that counting additional benefits could be used to justify more program spending and thus increase EmPOWER surcharges, which appear on ratepayer bills.

There is merit to at least some of these concerns. With a few exceptions, it is not possible to directly measure or ascribe monetary values to non-energy impacts. Evidence of the uncertainty associated with many of the non energy impacts is the large variance in results found between different studies. There is also an understandable aversion to using scarce utility energy efficiency program dollars to pay for participating customers' increased comfort or other benefits that do not contribute to the broader societal goals that the EmPOWER programs were intended to achieve – e.g., reduced cost of electric services, reduced emissions, and the reduced need to build power plants or defer shut down of old plants.

However, concluding that valuation of non-energy benefits is an uncertain enterprise does not lead to the conclusion that the value of the non-energy impacts is zero. In fact, they are almost certainly not zero. Not including non-energy impacts in the cost effectiveness estimates ensures with great certainty that the cost effectiveness estimates are wrong.

Moreover, to be consistent, aversion to counting participant benefits in the TRC should be complemented by an aversion to counting participant costs. Granted, the EmPOWER programs were not intended to increase participant levels of comfort. But by the same token, neither were they intended to increase Marylanders' costs. Thus, aversion to counting participant benefits would seemingly lead to the conclusion that the TRC test is an inappropriate test for evaluating program cost effectiveness and would suggest greater emphasis be placed on alternative tests such as the Program Administrator Cost (PAC) test.[2]

In sum, as long as the TRC is the primary benefit cost test used for the EMPOWER programs, all benefits to utilities, participants and, we would argue, society more generally (i.e., non-participants), should be considered and included to the extent feasible. Rather than focusing on

[2] At least several major energy efficiency advocacy organizations have recommended greater emphasis on the PAC test instead of the TRC, because of unwillingness or inability to include more expansive set of participant non-energy benefits. Organizations making this argument include the American Council for an Energy Efficient Economy (ACEEE), the Regulatory Assistance Project (RAP), and the Northeast Energy Efficiency Partnership (NEEP).

uncertainty, the EmPOWER cost effectiveness analyses should focus on expected value. In order to accomplish this, four sets of questions should be asked:

1) Has a clear and conceptual case been made for the existence of the non energy impact?
2) Is the proposed non-energy impact valuation as likely to be too low as too high?
3) Is the proposed non-energy impact valuation the best available in terms of quality analysis and cost trade-off?
4) Are the analysts, sources and assumptions generally credible?

In this analysis, we develop estimates of selected non-energy impacts that could be included in the ex ante and/or ex post cost effectiveness analyses for the EmPOWER Maryland energy efficiency programs. We also, recommend values that based on our analysis we have concluded will improve the accuracy of future EmPOWER cost effectiveness analyses and better align those analyses with EmPOWER policy objectives.

Four non energy impacts are included in this analysis: air emissions, comfort, commercial operations and maintenance (O&M), and utility bill arrearages. In all four cases, we provide a recommended value and methods for including them in future EMPOWER costs effectiveness analyses. For these non energy impacts, we would argue that the answer to all four questions above is “yes.”

The scope, methods and assumptions were reviewed and informed, but not directed, by the EmPOWER Cost Effectiveness Working Group. This Working Group draws on the expertise and perspectives of a diverse group of EmPOWER stakeholders, including Commission Staff, the Maryland Energy Administration, the EMPOWER utilities, the Office of Peoples Counsel, environmental organizations, and trade associations. While comments from the Working Group stakeholders greatly enhanced the quality of this analysis, the opinions in this report are the authors.

2

Air Emissions

2.1 Introduction

In this chapter, we examine the magnitude and potential methods for estimating air emissions benefits — associated with the EmPOWER programs. The focus is on uncompensated costs resulting from electricity consumption and the corresponding emissions associated with power generation -- specifically, carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxides (NOx). More broadly, we assess the feasibility and rationale for incorporating environmental externality costs in EmPOWER program ex ante and/or ex post cost effectiveness analyses.

Externality costs arise when an activity imposes uncompensated costs on other people. Ideally, environmental externality costs would be eliminated through emissions controls or compensated through emissions taxes. If the costs to society of these air emissions are not eliminated or incorporated into the price of electricity, more electricity will be consumed than is economically efficient and there will be an underinvestment in research, development and implementation of energy efficiency improvements, alternative electricity supply resources, and emissions controls.

Reductions in damages from air emissions are benefits to the people who were bearing the externality costs and, arguably, should be counted as a benefit in EMPOWER program benefit cost analyses.

2.2 Air Emissions Background

The scope of this discussion is limited to NOx, SO_2, and CO_2. While these three air emissions comprise a large share of the environmental externality costs associated with electricity consumption, many other externality costs exist that are not discussed here, including: particulate emissions, other greenhouse gas emissions such as methane for gas pipeline leaks and sulfur hexafluoride used in electric transformers; the impacts of mercury or particulates from combustion of coal and gas; the impacts of coal, gas or uranium extraction and transportation; emissions from heating fuel savings; nuclear waste and coal ash disposal. These other costs are beyond the scope of this study but could be considered in the future.

2.2.1 Nitrogen Oxides

Nitrogen oxides (NOx) are emitted from combustion of gas, oil and coal by electric utilities, industrial boilers and motor vehicles. NOx is a major precursor, along with volatile organic compounds (VOC) for ground level ozone. High ozone levels causes and aggravates acute and chronic respiratory problems. Ground level ozone also affects crops and can cause premature aging of paint and rubber.[1]

NOx emissions from electric generators and other large sources are regulated as "criteria pollutants" along with ground level ozone levels under the federal Clean Air Act administered and enforced by the U.S. Environmental Protection Agency (EPA). Maryland's Healthy Air Act prescribed emissions regulations that became effective in 2007 and were intended to attain compliance with federal regulations. According to MDE, the Healthy Air Act has reduced NOx emissions in Maryland by about 70 percent relative to 2002.[2]

In 2014, the Maryland Department of Energy (MDE) is developing new power plant regulations to comply with even more stringent federal ground level ozone standards of 75ppb.[3] Meeting the standards is made more challenging because approximately two-thirds of the ground level ozone formation is caused by NOx emissions originating outside Maryland. While local controls can still help with attainment, tighter regional/national controls on interstate transportation of emissions are also seen as necessary by State officials.[4]

The State of Maryland also imposes permit fees (currently $54.29/ton) for EPA criteria pollutants and non-criteria hazardous air pollutants. These fees are paid by all large power plants (Title V sources), as well as smaller state permitted plants. In addition to the per ton fees, Title V emitters pay a $5,000 annual base fee and other smaller state-permitted plants pay a $1,000 annual fee. These fees collectively total only a few cents per MWh and are not a consequential cost component in Itron's analysis.

According to the Maryland Department of Environment, 2013 was the cleanest year for ground level ozone since record keeping began in 1980.[5] While weather is a significant factor in year to

1 http://www.mde.state.md.us/programs/Air/AirandRadiationInformation/Pages/air/air_information/nitrogendioxide.aspx

2 See: http://www.mde.maryland.gov/programs/Air/Documents/GoodNewsReport2012/GoodNews2012finalinteractive.pdf.

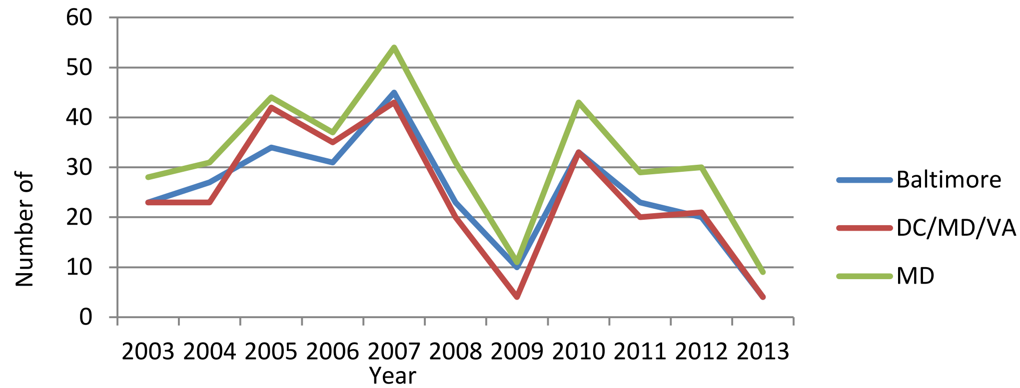
3 http://www.mde.state.md.us/programs/Air/Pages/MD_HAA.aspx#fed_comparison

4 Maryland Department of the Environment, "Meeting the New Ozone and Sulfur Dioxide Standards: What will it Take?," *2013 Power Plant Regulations Stakeholder Meeting*, October 21, 2013, p. 18.

5 Maryland Department of Environment, *Seasonal Report: 2013 Ozone*, viewed June 2, 2014, p.1, http://www.mde.state.md.us/programs/Air/AirQualityMonitoring/Documents/SeasonalReports/SeasonalReport_2013ozone.pdf

year variability in the number of non-attainment days for 8-hour ozone, the trend in the number of days generally seems to be declining, as shown in the figure below. The severity of non-attainment also seems to be on the decline (e.g., there have been no code purple days since 2006).[6] The improvements in ground level ozone correspond to significant reductions in statewide NOx emissions, which fell 70% between 2002 and ~~2012~~2013.[7]

Figure 2-1: Number of 8-Hour Ozone Exceedance Days



Source: Based on data from MDE, Historical Air Quality Data, downloaded June 2, 2014.

While air quality in Maryland has generally improved, Maryland still has room for improvement. The average number of non-attainment days was 25 in the previous five-year period 2008-12.[8] Baltimore has not even met the old pre-2008 one-hour standard for ozone of 85 ppb and is the only location in the Eastern United States that is still designated a "moderate" non-attainment area; other locations in the East are designated, at worst, "marginal" non- attainment areas.[9]

Moreover, meeting federal clean air requirements does not mean that ozone levels emissions have reached safe levels. While the current regulations were ultimately set at 75 ppb, the EPA's Clean Air Scientific Advisory Committee recommended ozone requirements of 60 ppb and 70

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6 Sunil Kumar, *Ozone Season Summary 2013*, power point presentation to Metropolitan Washington Area Council of Governments, June 11, 2013, p.4.

7 See: http://www.mde.maryland.gov/programs/Air/Documents/GoodNewsReport2012/GoodNews2012finalinteractive.pdf.

8 Maryland Department of Environment, *Seasonal Report: 2013 Ozone*, viewed June 2, 2014, p.1, http://www.mde.state.md.us/programs/Air/AirQualityMonitoring/Documents/SeasonalReports/SeasonalReport_2013ozone.pdf

9 See Maryland Department of Environment, Emission Reduction Credits Frequently Asked Questions, http://www.mde.maryland.gov/programs/Permits/AirManagementPermits/ERC/Pages/index.aspx. The Baltimore Region includes: Anne Arundel, Baltimore, Carroll, Harford and Howard Counties, along with Baltimore City.

ppb and stated that further benefits could be achieved at these more stringent levels.[10] The American Lung Association, which argues that the 2008 federal ozone standard is not stringent enough to protect human health, gave all but one of the 14 counties it graded an "F" for ozone in its 2013 State of the Air Report, making Maryland one of the worst states in the nation on this metric.[11]

Finally, while Maryland has been aggressive in reducing emissions of nitrogen oxides, roughly 70% of the nitrogen oxide emissions in Maryland come from outside the State, much of it generated within the PJM. To the extent that EmPOWER programs reduce PJM generation, they could also impact in-State nitrogen oxide levels.

2.2.2 Sulfur Dioxide Emissions

Sulfur Dioxide (SO_2) is emitted from fuel burning sources including electric utilities, industrial boilers, and vehicles. SO_2 emissions are a major contributor to fine particle pollution, thus increasing the severity of respiratory diseases. SO_2 emissions also react with water to cause acid rain, contributing to the acidification of forests and waterways and damaging vegetation and depleting fish populations.[12]

SO_2 emissions from electric generators and other large sources are regulated under the federal Clean Air Act. Maryland's Healthy Air Act prescribed emissions regulations that are the most stringent of any State on the East Coast. According to MDE, the Healthy Air Act has reduced SO_2 emissions in Maryland by about 80 percent relative to 2002.[13]

EPA requirements call for concentrations of no more than 75 ppb measured over one hour compared to the previous standard of 140 ppb averaged over 24 hours. The level of effort required to meet the EPA emission requirements is unknown since areas in Maryland, like most other parts of the country, have not yet been designated attainment or non-attainment. MDE is developing regulations and other early actions that can be taken to avoid areas in Maryland being

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10 Maryland Department of the Environment, "Meeting the New Ozone and Sulfur Dioxide Standards: What will it Take?," *2013 Power Plant Regulations Stakeholder Meeting*, October 21, 2013, p. 15.

11 American Lung Association, State of the Air 2013, p.99, http://www.stateoftheair.org/2013/assets/ala-sota-2013.pdf. The study is based on EPA air quality data for the three year period 2009 to 2011.

12 http://www.mde.maryland.gov/programs/pressroom/documents/sulphur.pdf

13 See: http://www.mde.maryland.gov/programs/Air/Documents/GoodNewsReport2012/GoodNews2012finalinteractive.pdf.

designated non-attainment areas by EPA. MDE has stated publicly that this will require additional focus on SO_2 from electric power plants and other large stationary sources.[14]

SO_2 emissions, like NOx and other criteria and hazardous non-criteria pollutants, are subject to permit fees (currently $54.29/ton) and annual base fees (see NOx, above). As mentioned above, these fees collectively total only a few cents per MWh and are not a consequential cost component in Itron's analysis.

Approximately 99% of the damages associated with SO_2 result from the transformation of SO_2 into coarse and fine particulates -- PM_{10} and $PM_{2.5}$, respectively. Significant reductions in SO_2 emissions have been achieved in Maryland with attendant improvements in the air quality of many areas of the State. As far back as 1997, most counties west of the Chesapeake Bay had been designated non-attainment areas for $PM_{2.5}$ by EPA. In 2013, MDE applied to EPA to have many of those counties redesignated as attainment areas, including Baltimore City and Anne Arundel, Baltimore, Carroll, Harford, Howard, and Washington counties.[15]

Likewise, the acidification of forests and streams has been largely mitigated by reductions in SO_2 emissions over the last two decades. At one time, Maryland's waterways and forests were exposed to some of the highest concentrations of sulfur dioxides in the United States. There seems to be little concern at this point about continued acidification of Maryland forests and waterways. A 2011 report of the National Science and Technology Council (NTSC) touts the significant human health benefits that have resulted from SO_2 (and NOx) emissions reductions and reports that some acid-sensitive areas are even showing signs of recovery. [16]

While reductions in SO_2 emissions have had significant and lasting effects on Maryland people and ecosystems, at least four counties (including the two largest by population) still remain on the EPA's non-attainment list for fine particulates ($PM_{2.5}$), namely: Montgomery, Prince Georges, Frederick, and Charles counties. In addition, the same NTSC Report that touted the major gains that have been made with respect to acid rains also concluded that additional

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[14] Maryland Department of the Environment, "Meeting the New Ozone and Sulfur Dioxide Standards: What will it Take?," *2013 Power Plant Regulations Stakeholder Meeting*, October 21, 2013, pp. 11, 29.

[15] Maryland Department of the Environment, Baltimore Nonattainment PM2.5 Redesignation Request, prepared for the U.S. Environmental Protection Agency, May 28, 2013, http://www.mde.state.md.us/programs/Air/AirQualityPlanning/Documents/PM2.5%20Redesignation%20Requests%20and%20Maintenance%20Plans/Baltimore%20NAA/Baltimore%20PM%20RR%20FINAL.pdf. And Maryland Department of the Environment, Washington County Nonattainment PM2.5 Redesignation Request, prepared for the U.S. Environmental Protection Agency, May 28, 2013, http://www.mde.state.md.us/programs/Air/AirQualityPlanning/Documents/PM2.5%20Redesignation%20Requests%20and%20Maintenance%20Plans/Washington%20County%20NAA/WashCo%20PM%20RR%20FINAL.pdf

[16] National Science and Technology Council, National Acid Precipitation Assessment Program Report to Congress: An Integrated Assessment, 2011, p. 87.

emission reductions are necessary in order to protect and further aid in the recovery of acid-sensitive ecosystems.[17]

2.2.3 Carbon Dioxide Emissions

Carbon dioxide emissions are emitted from the combustion of fossil fuels. Carbon dioxide is a major greenhouse gas, the main anthropogenic cause of global warming. Generation of electricity is the single largest source of CO_2 emissions. Maryland is particularly vulnerable to both the impacts of climate change – having the fourth longest coastline of any state – and the cost of abatement – more than 40% of electric consumption is generated from coal. Coal generation releases about twice as much CO_2 per Btu into the atmosphere as natural gas, with petroleum in between.

Historically, federal and state regulation of CO_2 has been minimal. Maryland has been a member of the Regional Greenhouse Gas Initiative (RGGI) since its inception in 2009. RGGI is a CO_2 cap and trade program in which member states commit carbon dioxide emission caps for electric power generators. Unlike most cap and trade regime, RGGI distributes allowances primarily through auctions – 94% of RGGI allowances through 2013 had been distributed via auctions. The RGGI caps to date have generally been non-binding – i.e., allowances have exceeded actual emissions.[18] This could change as a new model rule announced in 2012 will lower the RGGI caps by 2.5 percent annually through 2020.[19]

Despite the nonbinding caps, since the inception of RGGI in 2008, auction clearing prices for Maryland allowances have averaged $2.55 per ton. The new and more stringent caps under the new model rule have driven RGGI auction prices sharply higher. The Maryland clearing prices since the new model rule was announced have averaged $3.21 per ton and the latest auction cleared at $5.02 per ton. Through June 2014, Maryland cumulative proceeds from RGGI allowance auctions were $364 million. These revenues have been used to fund a variety of energy efficiency programs, alternative energy investments, abatement related activities, and

[17] National Science and Technology Council, National Acid Precipitation Assessment Program Report to Congress: An Integrated Assessment, 2011, p. 87.

[18] RGGI, Inc., *RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments*, p.1, http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf, viewed June 2, 2014. The RGGI allowance auctions have still generated proceeds because of an auction floor price, however. RGGI, Inc. claims reductions from investments of 2009-12 auction proceeds will reduce greenhouse gas emissions by 8 million short tons over the lives of the various measures.

[19] RGGI, Annual Report on the Market for RGGI CO2 Allowances: 2013, prepared by Potomac Economics, May 2014, p.5, http://www.rggi.org/docs/Market/MM_2013_Annual_Report.pdf.

energy bill assistance.[20] The allowance clearing price represents, in effect, a tax on CO_2 emissions.

More powerful regulations on electric carbon emissions could be forthcoming. Most notably, on June 2, 2014, EPA issued a proposed rule that would reduce CO_2 emissions from the power sector from 2005 levels by 30% by 2030. Our preliminary review suggests the proposed rule would establish a 2030 Maryland goal of 1,187 lbs. CO_2 per net MWh, which is more than a 30% reduction from 2013 levels (over 1700 lbs. per net MWh).[21] While much of the reductions in power plant carbon intensity will have to come from coal to gas conversion or plant retrofits, the proposed rule would allow a portion of the required reductions in power plant emissions intensity to be offset by energy efficiency improvements and investments in renewable energy.[22]

The federal carbon regulations will presumably require some additional emissions reductions in Maryland beyond those that will already be induced by the new RGGI caps. Given the carbon regulations are only "proposed" at this point and will be the subject of intense scrutiny and political wrangling in the coming months or years, derivation of an associated carbon price or compliance costs was beyond the scope of this analysis

2.3 Methods and Data

The following equation summarizes our estimation of EmPOWER air emissions benefits:

Air Emissions Benefits = MWh Savings x Emissions Intensity (lbs/MWh) x [Unit Damage Costs ($/lb) – Unit Emissions Taxes/Fees Paid by Utilities ($/lb)] = Total Benefits ($)

We calculate Total Benefits separately for NOx, SO_2, and CO_2. Benefits per kWh are then estimated:

Benefits per kWh ($/kWh) = Total Benefits ($) / [Total MWh Savings (MWh) x 1000]

Finally, we look at the impact of including the air emissions benefits on the 2011 Total Resource Cost Benefit-Cost estimates (TRC B/C).

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20 http://www.rggi.org/docs/Auctions/23/MD_Proceeds_By_Auction.pdf

21 For Maryland requirements see US Environmental Protection Agency, Carbon pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 40 CFR Part 60, RIN 2060, p.64, AR33 http://www2.epa.gov/sites/production/files/2014-05/documents/20140602proposal-cleanpowerplan.pdf. Current emissions are based on data from Luke Wisniewski, Maryland Department of Environment received March 14, 2014.

22 The EPA requested comments, due 120 days after publication, and is holding a series of workshops across the country on the proposed rule.

2011 TRC B/C with Air Emissions Benefits = [2011 Electric and Non-Electric Benefits ($) + Air Emissions Benefits ($)] / 2011 Program and Participant Costs

We describe the methods and data used to develop inputs for each of the equation parameters below.

2.3.1 MWh Savings

The scope of this emissions reductions analysis is limited to evaluated MWh savings from the utility-administered EMPOWER energy efficiency programs. ~~The 2013 verification was not finalized in time for this analysis, thus~~ Program Year ~~2012~~ 2013 evaluated savings are used. The ~~2012~~ 2013 programs included:

- Commercial and Industrial: Prescriptive, Small Business ~~and~~, Custom and Multifamily Master Metered (PEPCO only).
- Residential: Lighting, HVAC, Appliance Rebates and Recycling, Home Performance with Energy Star, Quick Home Energy Check Up, and New Construction.

The limited income programs are not included since they were not evaluated and verified in ~~2012~~time for this analysis. For the air emissions analysis, exclusions of the limited impact programs will not have a material impact on any of the results. The cents per kWh air emissions benefits estimated in this analysis can be applied to any program's electric savings.[23]

~~The analysis can be readily updated to reflect 2013 verified savings once they are finalized. Using the 2013 verified savings will increase the total air emissions benefits since the MWh savings was higher in 2013 than 2012. We do not expect it to materially affect the dollars per kWh air emissions benefits, nor the percentage impact on the Total Resource Cost estimates.~~

2.3.2 Emissions Intensity

Emissions intensities data were obtained from PJM Environmental Information Services Electricity Generation Attribute Tracking System (EGAT). EGAT data provides SO_2, NO_x and CO_2 emissions associated with PJM MWh generation by fuel type. These data are available for the years 2005 through 2013.[24]

[23] One exception to this would be for programs that are specific to obtaining peak savings. For these programs, the generation mix of avoided energy would be different than the average generation mix used in the current analysis. Because peak generation is "dirtier" than average, applying the air emissions benefits estimated in this analysis to peak programs would result in conservative avoided damage cost estimates.

[24] https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix

Our calculations implicitly assume that the EmPOWER MWh reductions coincide with the PJM average generation profile. The major factor driving our decision to use average generation mix rather than peak generation fuel mix is that we have no reason to think the EmPOWER MWh reductions are likely to affect peak loads more than base or intermediate loads. Based on discussions with the statewide evaluator, the utilities and others, we heard no arguments that peak generation fuel mix should be used.

All other things equal, using the average PJM average generation profile likely results in an underestimate of emissions. The PJM average generation profile is far less coal and fossil intensive than the marginal generation profile. As shown in the table below, marginal coal and fossil fuel percentages for 2012 and 2013 were significantly higher than the corresponding average generation percentages.

Table 2-1: Comparison of Average Coal and Fossil Generation MWh to Real-Time Marginal Units (% of Total Generation)

	Fuel	2012	2013
Average generation mix	**Coal**	42%	44%
	Fossil	62%	61%
Marginal generation mix	**Coal**	59%	58%
	Fossil	95%	95%

Sources: PJM, State of the Market Report: 2013, Table 3-6 and PJM Generation Attribute System, https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix.

2.3.3 Unit Damage Costs – NOx and SO_2

Our NOx and SO_2 damage cost inputs are based on National Academy of Sciences (NAS) *Hidden Costs* Study from 2010.[25]

<u>Hidden Costs Study Method and Results</u>

The *Hidden Costs* study is the only recent peer reviewed environmental externalities study with significant analytical support and potential applicability to the Maryland electric sector that we are aware of. The *Hidden Costs* study examined and estimated a wide range of externality costs associated with energy production and use, including electricity and fuels. It was funded by the US Department of the Treasury and was guided by more than 30 senior economist and other experts.

[25] National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010.

The *Hidden Costs* analysis of electricity generation was based on plant emissions data from the National Emissions Inventory of 406 coal-fired and 498 gas-fired power plants in 2005. Monetized damages per ton of EPA criteria pollutant were estimated using the Air Pollution Emissions Experiments and Policy (APEEP) model, which calculates the monetized damages resulting from exposure by populations to various pollutants.[26]

The vast majority of air emissions damages were related to health impacts and mortality was by far the largest category of heath impacts.[27] Other health impacts included chronic bronchitis, asthma, emergency hospital admissions for respiratory and cardiovascular disease. While impacts on visibility, crop and timber yields, buildings and infrastructure, and recreation were also considered, they were small in comparison to health impacts. Some ecosystem damages were not estimated, including impacts of acid rain from SO_2 and NOx on forests and fish populations and the eutrophication of water ecosystems from nitrogen deposition.[28]

Table 2-2: APEEP Value of Human Health Effects*

Health Event	Unit	U.S. Dollars
Chronic Exposure Mortality	Case	5,910,000
Chronic Bronchitis	Case	320,000
Chronic Asthma	Case	30,800
General Respiratory	Hospital Admission	8,300
General Cardiac	Hospital Admission	17,526
Asthma	Hospital Admission	6,700
COPD	Hospital Admission	11,276
Ischemic Heart Disease	Hospital Admission	18,210
Asthma	ER Visit	240

[a]Values are in 2000 U.S. dollars; see Muller and Mendelsohn 2007.

SOURCE: Modified from Muller and Mendelsohn 2006.

* National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010, Appendix C, p.428.

Health impacts were calculated using concentration-response functions employed in regulatory impact analyses by EPA. A variety of non-market valuation studies were used for other health impacts. Human mortality was valued using EPA's statistical value of a life, equal to about $6

[26] For a detailed description of the APEEP model and its relative strengths and weaknesses, see National Research Council Study, *Hidden Costs of Energy*, pp. 64-125 and pp. 423-31.

[27] Ibid, p. 84.

[28] Ibid, p. 85.

million, as shown in the table above, which reports the values attributed to various chronic and acute health events.[29]

The concentration response functions and valuation of mortality are two major sources of uncertainty with respect to these types of damage cost estimates. The dominance of human mortality in the damages estimates makes the results sensitive to the mortality valuation. If a human life was valued at $2 million rather than $5.9 million, for example, the weighted average damages from coal would be about two-thirds lower.[30] On other hand, if another popular concentration response model had been used, the damages would have been three times higher.

The tables below presents the Hidden Cost Study estimates of monetized damages per kWh from 2005 vintage coal and gas generation. As shown, per kWh damages associated with various plants throughout the United States vary widely. Most notably, for coal plants the SO_2 per kWh damages of plants in the top 95th percentile were 50-times the damages of the bottom 5^{th} percentile. For gas plants, NOx emissions in the top 95th percentile were 714-times the damages of the bottom 5^{th} percentile.

[29] Note that mortality estimates do not include deaths of workers in coal or gas production or distribution, since these valuations are assumed to be included in the wages charged by labor and passed through to electricity prices.

[30] National Research Council Study, *Hidden Costs of Energy*, pp. 93-95.

Table 2-3: Distribution of Criteria Air Pollutant Damages per Kilowatt-Hour Associated with Emissions from 406 Coal-Fired Power Plants in 2005 (2007 Cents)

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO_2	3.8	4.1	0.24	1.0	2.5	5.2	11.9
NO_x	0.34	0.38	0.073	0.16	0.23	0.36	0.91
$PM_{2.5}$	0.30	0.44	0.019	0.053	0.13	0.38	1.1
PM_{10}	0.017	0.023	0.001	0.004	0.008	0.023	0.060
Total (equally weighted)	4.4	4.4	0.53	1.4	2.9	6.0	13.2
Total (weighted by net generation)	3.2	4.3	0.19	0.71	1.8	4.0	12.0

NOTE: In the first five rows of the table, all plants are weighted equally; that is, the average damage per kWh is 4.4 cents, taking an arithmetic average of the damage per kWh across all 406 plants. In the last row of the table, the damage per kWh is weighted by the electricity generated by each plant to produce a weighted damage per kWh.

ABBREVIATIONS: SO_2 = sulfur dioxide; NO_x = oxides of nitrogen = PM, particulate matter.

National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010, Table 2-9, p.92

Table 2-4: Distribution of Criteria-Pollutant Damages per Kilowatt-Hour Associated with Emissions from 498 Gas-fired Power Plants in 2005 (Cents based on 2007 U.S. Dollars)

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO_2	0.018	0.067	0.00013	0.00089	0.0022	0.006	0.075
NO_x	0.23	0.74	0.0014	0.013	0.038	0.16	1.0
$PM_{2.5}$	0.17	0.56	0.00029	0.007428	0.026	0.08	0.75
PM_{10}	0.009	0.029	0.00003	0.00043	0.0014	0.0042	0.036
Total (unweighted)	0.43	1.2	0.0044	0.041	0.11	0.31	1.7
Total (weighted by net generation)	0.16	0.42	0.001	0.01	0.036	0.13	0.55

NOTE: In the first five rows of the table, all plants are weighted equally; that is, the average damage per kWh is 0.43 cents, taking an arithmetic average of the damage per kWh across all 498 plants. In the last row of the table, the damage per kWh is weighted by the fraction of electricity generated by each plant to produce a weighted damage per kWh.

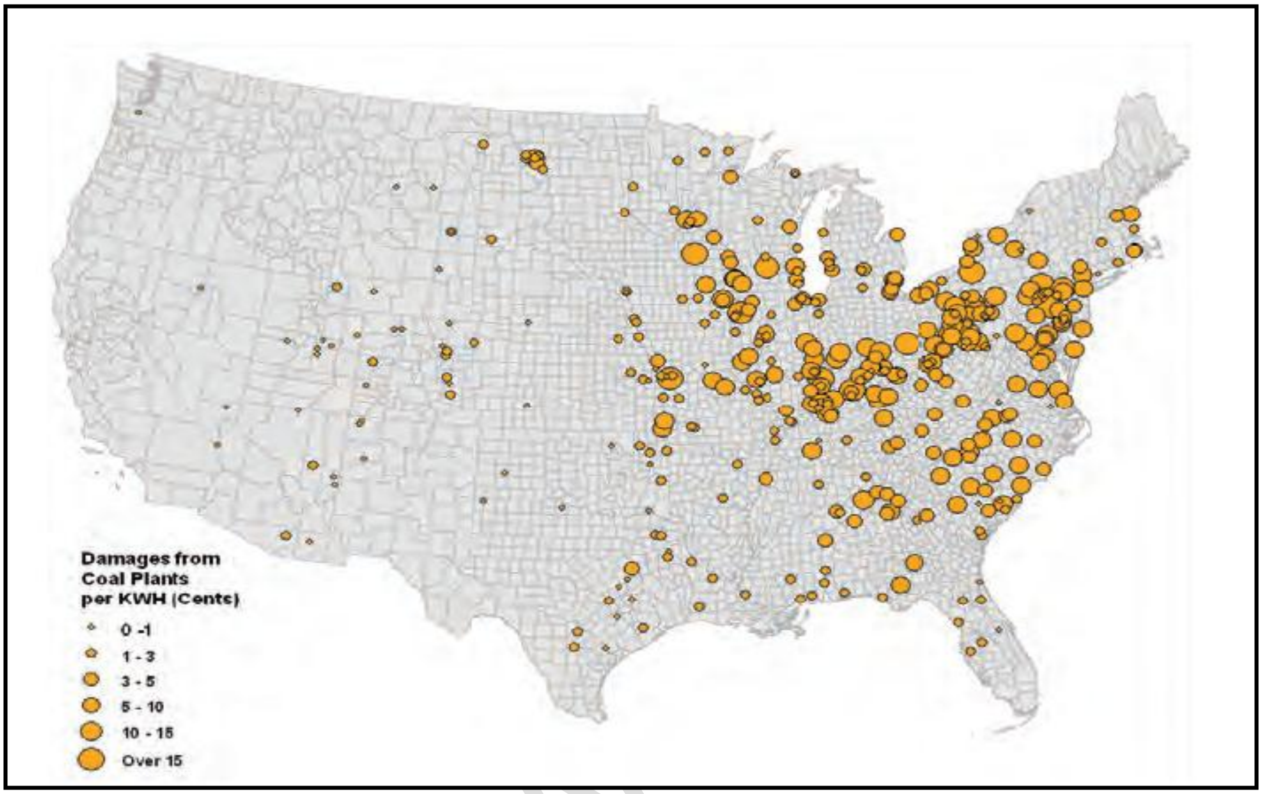
ABBREVIATIONS: SO_2 = sulfur dioxide; NO_x = oxides of nitrogen; PM = particulate matter.

National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010, Table 2-15, p.118.

For our analysis, we multiplied the mean per kWh damages for each emissions type by the ratio of the total weighted average to the total simple average. This was intended to approximate the weighted average damages per kWh for each emission type. While we did not have access to the individual plant results from the Hidden Cost Study, the figures show the geographic distribution of damages per KWh for plants included in the NAS study., These figures suggest that, if anything, the weighted mean probably understates the per kWh damages associated with PJM coal and gas plants in 2005 due to the relatively higher concentration of large damage cost plants in the PJM service territory.[31]

[31] Admittedly, the figures provide only modest support for this claim. The study team did have access to the county level damage cost estimates used in the NAS study. An attempt was made to combine these county level data with EPA emissions data from every coal and gas fired generator in PJM territory (http://epa.gov/cleanenergy/energy-resources/egrid/index.html) to form a fully custom emissions analysis.

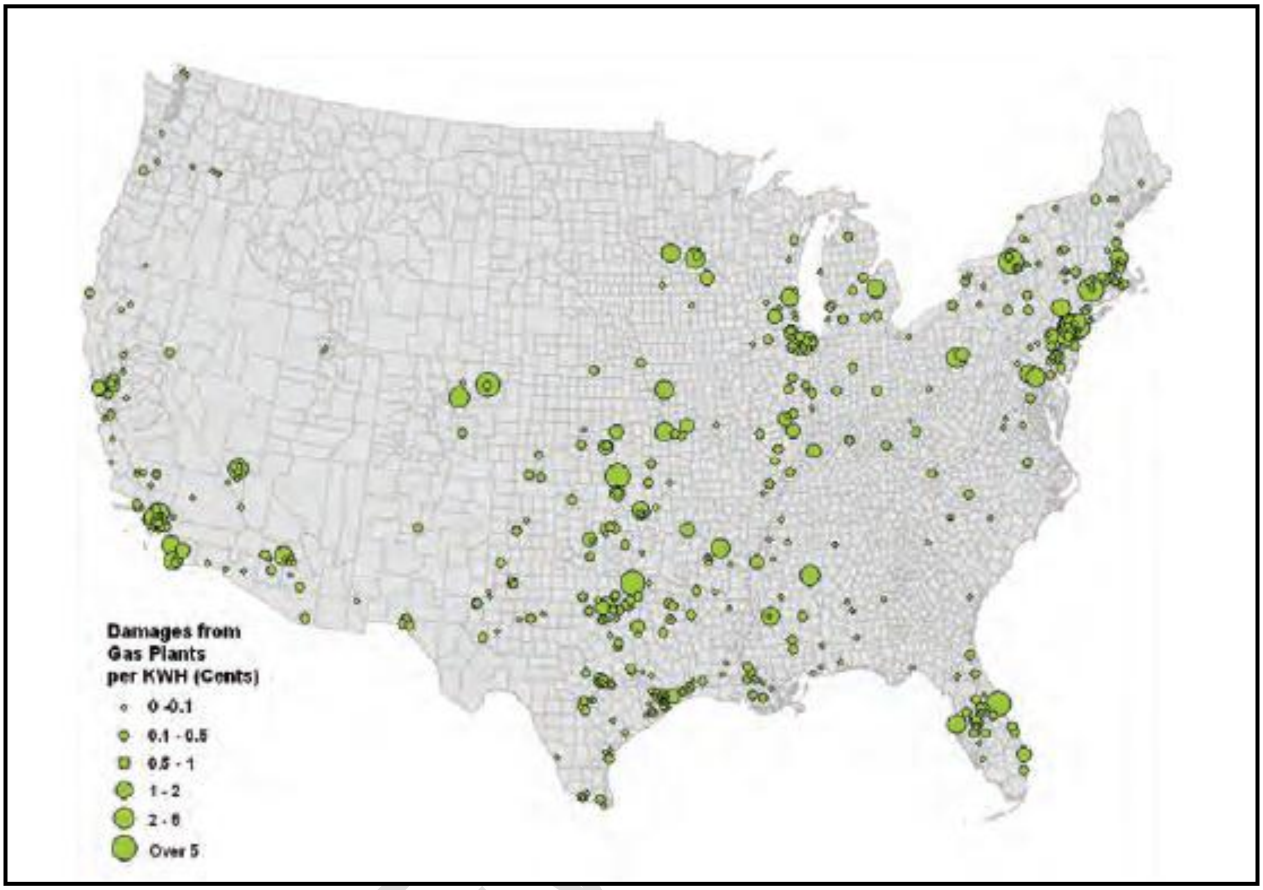
Figure 2-2: Regional Distribution of Air Pollution Damages from Coal Generation per kWh in 2005 (U.S. dollars, 2007) *



National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010, Figure 2-2, p.118.

However, this analysis is not included because the emissions data obtained from the EPA did not reconcile with system wide emissions reported by PJM, presumably due to the inclusion of energy imports. Although the study team believes the damage estimates presented in this analysis to be conservative, the wide variability in damages indicated in Table 2-3 and Table 2-4 may justify a more robust county level analysis in the future.

Figure 2-3: Regional Distribution of Criteria-Air-Pollutant Damages for Gas Generation per kWh (U.S. dollars, 2007)



National Research Council Study, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption*, 2010, Figure 2-17, p.122

Changing Emissions Intensity

Our analysis further adjusts the *Hidden Costs* coal plant value to account for dramatic reductions in NOx and SO_2 emissions intensity that have occurred since 2005. Total environmental externality damages associated with NOx and SO_2 have been significantly reduced in recent decades through regulations requiring emissions reductions and other policies. Maryland utilities alone have invested $2.6 billion in pollution controls to comply with the Healthy Air Act.[32] Our

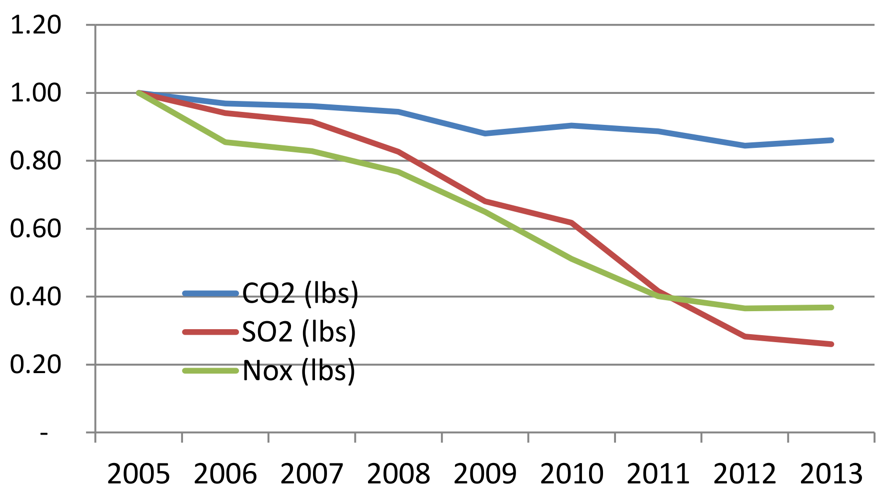
[32] Maryland Department of the Environment, *Clean Air Progress in Maryland 2012*, p.6, http://www.mde.maryland.gov/programs/Air/Documents/GoodNewsReport2012/GoodNews2012finalinteractive.pdf.

analysis reflects both historical and projected future reductions in emissions and emissions intensities (emissions per MWh) from coal and gas generators.

Overall Emissions Intensity

As shown in the figure below, for the PJM generation mix as a whole, 2013 SO_2 and NOx emissions per MWh were two thirds to three fourths lower than in 2005. CO_2 emissions per MWH fell as well, though not nearly so dramatically.

Figure 2-4: PJM Emissions per Total MWH, 2005–2013



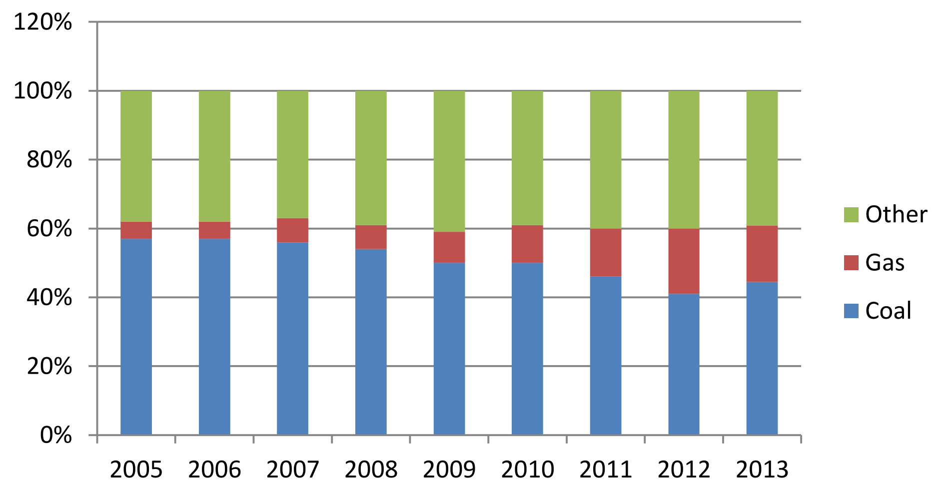
Source: Itron calculations based on PJM Environmental Information

Emissions reductions can result from a number of factors including changes in fuel mix, additional emissions controls, improved plant efficiencies and fuel quality. To make adjustments to the Hidden Costs values, we needed to understand the sources of the reduced emissions intensities.

Generation Fuel Mix

The following figure shows how PJM fuel shares of coal and gas changed from 2005 thru 2013. Together, gas and coal have maintained a roughly 60% share of total MWH generation, but their respective shares have changed significantly. Gas generation increased from just 5% of overall generation in 2005 to 16% in 2013, while coal generation went from 57% to 44%. Even if no emissions controls were adopted, these fuel mix changes alone would have enormous impact on criteria and CO_2 emissions; natural gas combustion results in roughly half the CO_2 emissions of coal and produces a relatively trivial amount of SO_2 emissions.

Figure 2-5: Changing Shares of Coal and Gas Generation in PJM, 2005–2013

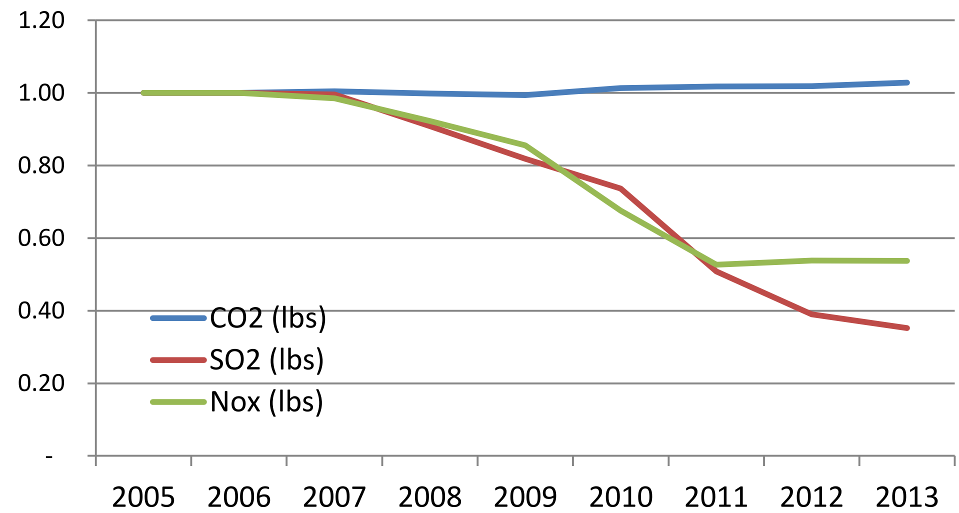


Source: Itron calculations based on PJM Environmental Information Services Electricity Generation Attribute Tracking System

Plant Emissions Intensity

Plant emissions intensities can change as a result of increased emissions controls, changes in the quality of fuels, and/or plant efficiency improvements. For economic as well as regulatory reasons, most reductions in plant emissions intensity are the result of new plants coming on line, though some may be the product of existing plant retrofits. The following two figures show the marked improvements that have been made from emissions controls and improved plant efficiencies for PJM's coal and natural gas generation, respectively.

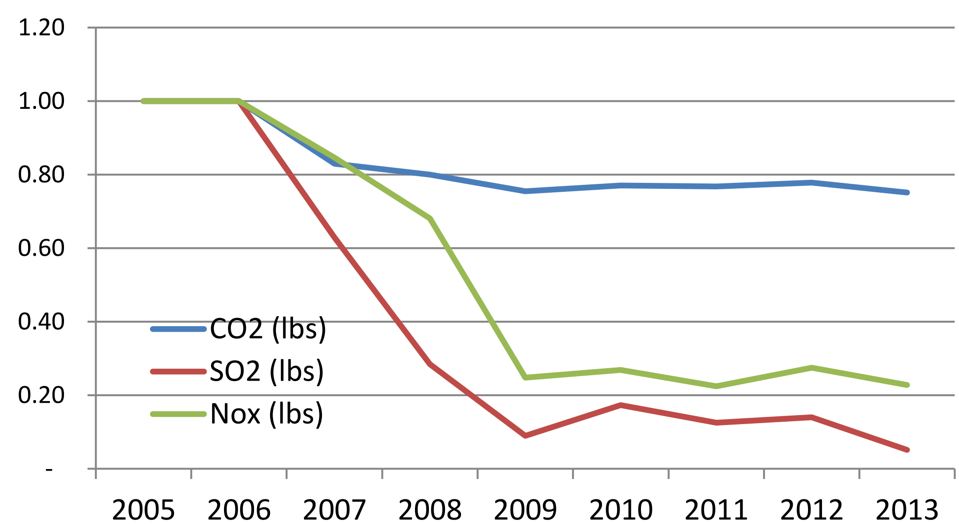
Figure 2-6: PJM Coal Generation Emissions per MWh, 2005–2013



Source: Itron calculations based on PJM Environmental Information Services Electricity Generation Attribute Tracking System

Criteria emissions per MWh generated from coal plants in 2013 were roughly one half of 2005 levels. The emissions intensity reductions are mostly from emissions controls. The use of sub-bituminous (i.e., low sulfur) coal contributed some to the reduction; it was nine percent of coal generated MWH in 2005 and 13 percent in 2013. The CO_2 trend line indicates little if any improvement in the efficiency (lower Btu input per MWH) of the coal plant fleet.

Figure 2-7: PJM Gas Generation Emissions per MWh, 2005–2013



Source: Itron calculations based on PJM Environmental Information Services Electricity Generation Attribute Tracking System

Criteria emissions per PJM MWh generated from gas plants in 2013 were only about one fifth of 2005 levels. The CO_2 trend line suggests roughly one fourth of the reduction in criteria emissions intensity was the product of more efficient plants (lower Btu input per MWH) coming on line and to a lesser degree retrofits of existing plants. The bulk of the emissions intensity reductions are from more stringent emissions controls requirements.

Adjustments to Hidden Costs Study Cost Estimates to Account for Past Changes in Emissions Intensity

The table below shows the changes in PJM emissions intensity (lbs per MWh) that have resulted from plant improvements and fuel switching for each fuel in 2013 compared to 2005, the year upon which the *Hidden Costs Study* damage cost estimates were based. Our analysis reflects these changes.

Table 2-5: Emissions Intensity 2013 as Percent of 2005

Gen Fuel	NOx	SO_2	CO_2
Coal	54%	35%	103%
Gas	23%	5%	75%

Source: Itron calculations based on PJM Environmental information Service data, https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix

2.3.4 Adjustments for Future Changes in Emissions Intensity

The Hidden Costs Study projected damage costs per kWh out to 2030 using Energy Information Administration projections of national electricity consumptions increases and emissions decreases. For both coal and gas, damages per kWh in 2030 were expected to be lower than in 2005 as increases in damages per ton resulting from population growth and growing wages (affecting statistical value of life) were expected to be more than offset by emissions intensity reductions. Coal plant damages per kWh in 2030 were expected to be 40% lower than 2005 damages per kWh. Damages per kWh from gas generation were expected to be 32% lower in 2030.[33]

Above we described adjustments that we made to the Hidden Costs Study damage costs per kWh values to reflect historic reductions in gas and coal SO_2 and NOx emissions intensity from 2005 thru 2013. Those adjustments already far exceed the 2030 projections of the Hidden Costs

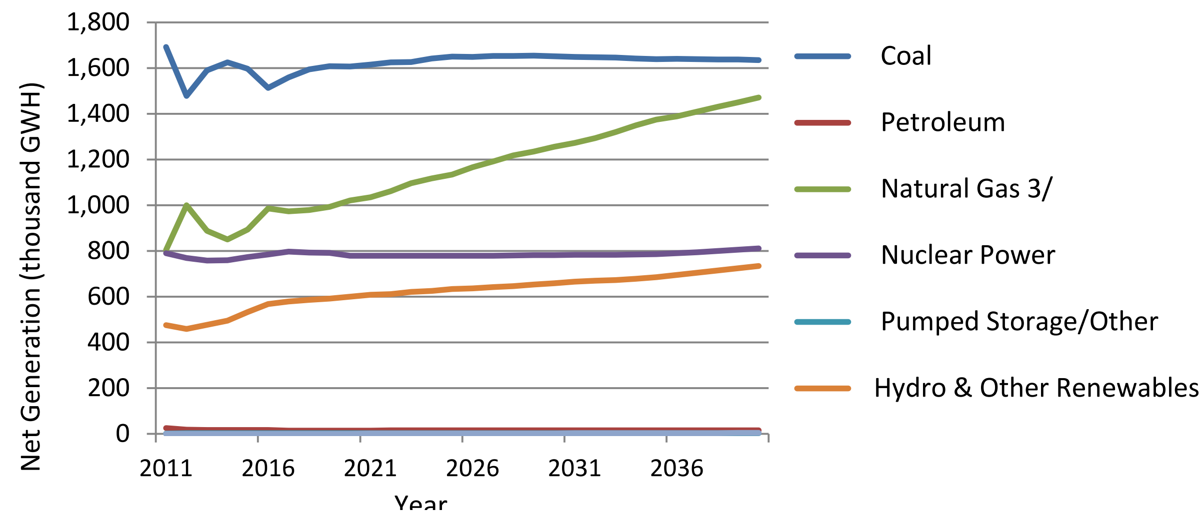
[33] National Research Council Study, *Hidden Costs of Energy*, pp. 104-109 for discussion of coal generation projections and pp. 124-5 for gas generation.

Study. Nevertheless, additional adjustments were still needed to reflect projected changes in fuel mix and corresponding change in aggregate emissions intensities.

We do not adjust for future improvements in emissions intensity resulting from emissions controls since those will presumably result in additional costs to utilities, which will be included in future avoided costs projections. In other words, reductions in damage costs will be partially offset by increased emissions control costs.

Damage costs resulting from changes in the generation fuel mix would not be captured in utility avoided cost projections, however. As shown in the figure below, EIA projects significant increases in natural gas generation and hydroelectric and other renewable resources, while coal and nuclear generation are expected to remain roughly flat.

Figure 2-8: U.S. Projected Net Generation through 2040



Source: Data from Energy information Administration, *Annual Energy Outlook 2014*, Table A8.

Between 2013 (the last year we adjusted for) and 2024 (the projected weighted average life of measures in the 2014 portfolio is ~~10~~ 12 years) , the share of coal nationally is expected to go from 43% of total generation down to 39%, while gas is projected to increase from 24% to 27%.[34]

Assuming proportional changes in the PJM fuel mix decreases the estimated SO_2 emissions per kWh by six percent. Projected fuel mix changes reduce estimated NOx damages per kWh by five percent and CO_2 damages by less than one percent.

[34] Source: Data from Energy Information Administration, *Annual Energy Outlook 2014*, Table A8.

2.3.5 Criteria Pollutant Damages per kWh Values Used in Our Analysis

The table below adjusts the *Hidden Costs* damages per kWh values to reflect the discussions above. In sum, the adjustments include: 1) conversion from simple average to weighted average damage costs, 2) historical 2005-2013) reductions in emissions intensity, and 3) converts the *Hidden Costs* damages from 2007 dollars to 2013 dollars. As shown, the SO_2 and NOx damages per kWh used for our analysis are only a fraction of the values from the *Hidden Costs* Study.

Table 2-6: Summary of Criteria Emissions Unit Damage Calculations

	Hidden Costs Simple Average cents/kWh Damages ($2007)		**Ratio of Total Weighted Average to Average $/kWh**	**Weighted Average cents/kWh Damages ($2007)**		**Ratio 2013 to 2005 Emissions Intensity**		**Adjusted Damages cents per kWh ($2007)**		**Adjusted Damages cents per kWh ($2013)**	
Type	**NOx**	**SO_2**	**Combined**	**NOx**	**SO_2**	**NOx**	**SO_2**	**NOx**	**SO_2**	**NOx**	**SO_2**
Coal	0.34	3.8	73%	0.25	2.76	54%	35 %	0.13	0.97	0.15	1.12
Gas	0.23	0.02	37%	0.09	0.01	23%	5%	0.02	0.00	0.02	0.00
Sources	Calc NAS, Tables 2-9 & 2-15			Calc		Calc PJM EIS		Calc		Calc CPI	

As a final note, the *Hidden Costs* study estimates of damages per kWh are a function of emissions per kWh (emissions intensity) and the dollar damages per ton of emissions. For both coal and gas plants, emissions per kWh are the dominant driver of the damages per kWh values. Emissions per kWh are a function of fuel quality (e.g., high versus low sulfur coal), emissions controls and the plant age. Damages per ton of emissions are a function of the plant's proximity to population centers and stack heights.[35]

As discussed above, we adjusted for changes in emissions per kWh since 2005 and for projected changes through 2024. We did not adjust values for damages per kWh to reflect changes subsequent to 2005 in damages per ton of emissions. In other words, we assume that the damages per ton are independent of the number of tons. According to the Hidden Cost Study this is consistent with the epidemiological literature and with EPA calculations, which assume that damages per ton of emissions are constant throughout the relevant ranges of values.[36] While we accepted this assumption for our current analysis, this assumption should be tested in the future given the large decreases in emissions that have occurred over the last decade.

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[35] National Research Council Study, *Hidden Costs of Energy*, pp. 91.

[36] Ibid, pp. 88.

2.3.6 Unit Damage Costs – CO_2

For our CO_2 damage costs inputs, we used the latest social cost of carbon estimates developed by the federal government's Interagency Working Group on Social Cost of Carbon in 2013.[37] These values are used by federal government agencies for their regulatory analyses. The social cost of carbon estimate is "intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change."

Three social cost of carbon estimates are provided based on 2.5, 3 and 5 percent discount rates, using the average results from three models and five socioeconomic scenarios. A fourth carbon cost estimate is the 95th percentile of the estimates using a 3 percent discount rate and is intended to represent higher than expected economic impacts. The average results using the 3 percent discount rate is "the central value," but the Interagency Group "emphasizes the importance and value of including all four [carbon cost] scenarios.[38] Including the 95th percentile at a 3 percent discount rate is important because it highlights the variability in damage costs that exist within each discount rate scenario. As Table 2-7 shows, the damages in the 95th percentile are nearly three times higher than the mean. The wide variation is due to uncertainty surrounding the extent of future gross domestic product (GDP) losses resulting from climate change. So, while it is clear that assumptions regarding discount rate have large impacts on the results of this analysis, it is important to realize that there is substantial uncertainty within each scenario that is not explicitly accounted for.

The table below presents the four Interagency Group carbon cost estimates in 1-year intervals starting in 2014. The weighted average estimated useful life of the ~~2012~~ 2013 EmPOWER program measures was ~~10~~ 12 years so we base our analysis on the average CO_2 values between 2014 and 2024.

[37] Interagency Working Group on Social Cost of Carbon. United States Government, Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866, May 2013.

[38] Interagency Working Group on Social Cost of Carbon. United States Government, Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866, May 2013, p.12.

Table 2-7: Social Cost of Carbon Dioxide ($2007 per Metric Ton)

Selected Years \ Discount Rates	5% Average	3% Average	2.5% Average	3% 95th Percentile
2014	11	37	57	106
2015	12	38	58	109
2016	12	39	60	113
2017	12	40	61	117
2018	12	41	62	121
2019	12	42	63	125
2020	12	43	65	129
2021	13	44	66	132
2022	13	45	67	135
2023	13	46	68	138
2024	14	47	69	141
Average 2014 thru 2024	**12**	**42**	**63**	**124**

Source: Interagency Working Group on Social Cost of Carbon. United States Government, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis* – Under Executive Order 12866, May 2013, p.18.

As noted above, between 2013 (the last year we adjusted for) and 2024 (the weighted average life of measures in the 2014 portfolio) , the share of coal is expected to go from 43% of total generation down to 39%, while gas is projected to increase from 24% to 27%.[39] These changes in fuel mix decrease the overall CO_2 emissions per kWh, and thus damage costs per kWh, by less than 1%. We multiply the EmPOWER program emissions reductions by 0.99 to reflect the projected reduction in CO_2 intensity resulting from fuel mix changes.

2.3.7 Carbon Taxes and Fees

As noted above, Maryland generators are subject to permit fees for EPA criteria emissions and must purchase allowances for carbon dioxide emissions as part of Maryland's participation in RGGI. Those fees are subtracted from the externality damage cost estimates in our analysis. As discussed in previous sections, the criteria permit fees add up to only a few thousandths of a cent per kWh in Maryland. Consequently, they have no impact on our benefits estimates.

Utility spending for RGGI allowances are significant, however. We adjusted CO_2 damages costs to reflect the effective carbon price created by the RGGI allowance auctions. The presumption is that the RGGI allowance prices are counted in utility avoided generation cost forecasts. If we did not reduce the allowance purchases from the benefits, we would in effect be double counting

[39] Source: Data from Energy information Administration, *Annual Energy Outlook 2014*, Table A8.

them – i.e., they would be included in the avoided supply costs and in the externality damage costs.

We made several adjustments to historical RGGI allowance auction prices. Table 2-8 shows RGGI auction clearing prices before and since the new RGGI rules (discussed on p. 2-6) were instituted. The new rules will lower the RGGI emissions caps and, all else equal, would be expected to increase allowance prices.

We also adjusted for allowance set asides. Set asides are distributed to states, which can distribute them to emitters at their discretion. States may offer the set asides to particular entities at no or low cost, or as credits for CO_2 reductions achieved between 2006 and 2008. About six percent of total allowances distributed to date by RGGI as a whole have been set asides.[40] However, in past years at least some states have simply retired many of these set aside allowances, rather than sell or give them away.

Based on perusal of RGGI auction results, it appears that only 1.8 million of Maryland's allowances have actually been distributed outside auctions, compared to 143 million allowances than have been auctioned. Even assuming that all of Maryland's distributed set aside allowances were given for free, the effective per ton CO_2 price to date would still be nearly 99 percent of the auction clearing price. The average allowance price assuming all Maryland set asides that were distributed were given away for free in reported in the last column of the table.

[40] RGGGI, 2013 Annual Report, p.14. RGGI also offers allowance offsets for CO2 reductions achieved through CO2 reduction or sequestration projects occurring outside the capped electric generation sector, but no offsets have been awarded to date.

Table 2-8: Comparison of Auction Results Before and After the New Model Rule Announcement

Auction #	Auction Allowances	Auction Proceeds ($)	Auction Clearing Price ($)	Auction Date	Average Price incl Set Asides
Auction 19	9,579,963	26,823,896	$2.86	13-Mar	$2.83
Auction 20	9,579,963	30,751,681	$3.28	13-Jun	$3.25
Auction 21	8,739,921	23,335,589	$2.73	13-Sep	$2.70
Auction 22	8,739,920	26,219,760	$3.06	13-Dec	$3.03
Auction 23	4,842,487	19,369,948	$4.00	14-Mar	$3.96
Auction 24	3,725,941	18,704,224	$5.02	14-Jun	$4.97
Since New Rule (Auctions 19-24)	45,208,195	145,205,097	$3.26	Mar-13 thru Jun-14	$3.23
Pre New Rule	97,522,982	219,115,649	$2.25	Sep-08 thru Dec-12	$2.22
All Auctions	142,731,177	364,320,747	$2.55	Sep-08 thru Jun-14	$2.53

Sources: Data compiled and/or calculated from the following RGGI website reports: http://www.rggi.org/docs/Auctions/24/MD_Procceds_By_Auction.pdf; and http://www.rggi.org/market/co2_auctions/results.

At least two conceptual challenges emerged in estimating an effective RGGI carbon price to be subtracted from the CO_2 damage cost.

First, auction clearing prices have varied significantly and recent changes in RGGI program have led to significant auction price increases since the end of 2012. As shown in the table below, since the inception of RGGI in 2008, auction clearing prices for Maryland allowances averaged $2.55 per ton. However, the Maryland clearing prices since the new model rule was announced have averaged $3.26 per ton and the latest auction cleared at $5.02 per ton.

A second uncertainty is the large number of surplus allowance holdings. According to RGGI, there were 140 million surplus allowances as of the end of 2013.[41] Over half of those surplus allowances are in the hands of investors. Some of these "banked" allowances could turn out to have been overvalued by auction buyers if actual emissions do not increase significantly above future caps or new rules requiring that banked allowances be used.

[41] RGGI, 2013 Annual Report, pp. 8 and 33. As of December 31, 2013, 319 million allowances were in circulation with only 179 million needed to cover cumulative emissions. More than half of the surplus allowances were held by investors.

Ultimately, allowance values will be determined by a combination of economic, demographic, and regulatory decisions that are difficult to predict. EPA carbon regulations could reduce actual emissions and, unless RGGI caps are lowered, the need for RGGI allowances. The EPA regulations would then lower RGGI allowance values. In the extreme and unlikely event that Maryland followed New Jersey and withdrew from RGGI, the Maryland surplus allowances could be worth nothing.[42] On the other hand, a major economic boom, growing population or higher than anticipated cost of emissions control, could cause actual emissions to be greater than anticipated by investors, thus making the actual value of the allowances greater than the average auction clearing price.

For our base case, we used the average auction clearing price since the new rule of $3.26 per ton, which, when applied to 99 percent of emissions gives a CO_2 price of $3.23 per ton. Ideally, the RGGI allowance price assumption used to adjust damage costs should be equal to the allowance price assumption used by utilities for their avoided costs forecasts. But we do not know what future allowance prices will be, or more specifically, the prices that will be assumed in utility avoided costs forecasts. The average clearing price in the latest auction – as shown in Table 2-8, the March 2014 auction clearing price was $5.02 per ton, which applied to 99% of emission would equal $4.97. At least one RGGI study projected that allowance prices would reach $10 by 2020. A low end estimate of the RGGI carbon price might be based on the auction reserve price of $1.93 per ton applied to 99% of emissions, which would equate to a CO_2 price of $1.91 per ton.

Final Carbon Price

The table below shows adjustments we made to the Interagency Working Group carbon price estimates. Adjustments included 1) converting from 2010 to 2013 prices, and 2) subtracting RGGI allowance prices.

Table 2-9: Adjustments to Federal Regulatory Carbon Prices

Interagency Task Force CO_2 Damage Costs per Ton ($2010)			Adjusted CO_2 Damage Cost per Ton ($2013)			RGGI Allowance Price per Ton ($2013)	Net (minus RGGI allowance price) CO_2 Damage Cost per Ton ($2013)		
@5%	@3%	@2.5%	@5%	@3%	@2.5%		@5%	@3%	@2.5%
12	42	63	14.19	48.19	72.60	$3.26	10.92	44.93	69.34

[42] New Jersey withdrew from RGGI in 2011. RGGI 2013 Annual Report, p.12.

2.3.8 Costs of Compliance with Existing Regulations

Some Cost Effectiveness Working Group members expressed concern that we could be double counting emission control costs. Existing emission control costs and fees are presumably included in utility avoided costs projections. Even some future compliance costs could be included in avoided cost projections to the extent that these forward costs are anticipated and included, for example, in PJM Reliability Pricing Model auction bid prices.

Our analysis does not double count emissions control costs. There is no overlap between reduced air emissions damages and already curtailed emissions – damage costs arise from emissions that have not been curtailed.

As discussed above, there is, overlap between emissions externality costs and emissions that are subject to fees, such as the Regional Greenhouse Gas permits and the criteria air emission permits. Those fees are subtracted from the externality damage cost estimates in our analysis. If the fees were not subtracted, the emission permit value would be double counted – i.e., included in the avoided supply costs and in the externality damage costs.

2.3.9 Emissions Scope

Approximately 70% of the ozone measured in Maryland originates in NOx emissions from upwind states. PJM electricity coming into Maryland could be generated as far away as Illinois. It is consequently unclear the extent to which a kWh reduction from EMPOWER programs will impact in-state emissions or emissions concentrations.

Estimating the air emissions benefits specific to Maryland residents is beyond the scope of this analysis. Analysis of criteria emissions benefits would require development of Maryland concentration response functions and analysis of air emissions transport into and out of the State. While challenging, this analysis at least is conceptually grounded in existing models, such as those used for the Hidden Costs study. Therefore, developing reasonably accurate estimates of the benefits to Maryland residents of EmPOWER induced reductions in criteria emissions is probably feasible, though it would require significant investment.

Whether such an effort would be worthwhile is another question. Even in the aggressive case, our analysis concludes the sum of criteria emissions benefits totals less than one cent per kWh saved, which is unlikely to materially affect EmPOWER cost effectiveness either at the program or portfolio levels – i.e., only rarely, will a TRC B/C ratio go from less than one to greater than one if given additional benefits of 0.8 cents per kWh.

It is not clear what even the conceptual basis for allocating the impacts of CO_2 reductions to Maryland residents would be. CO_2 emissions originating in Maryland and the PJM will flow into the global stock of atmospheric CO_2. Maryland residents will be affected as much by a ton of

CO_2 emitted in Asia as in Maryland. The Interagency Working Group on Social Cost of Carbon acknowledged this issue and chose to count global damages from a ton of carbon.

Cost Effectiveness Working group members offered several opinions on the question of allocation of criteria emissions and CO_2 to Maryland residents. Some members felt this was an additional point of major uncertainty that further undermines any attempt to estimate and apply an air emissions benefit to the EmPOWER program cost effectiveness. This argument does not get around the fact that emissions benefits are not zero and that a well vetted, though still highly uncertain, non-zero value could be more accurate than the currently assumed benefit of zero.

At the other end of the spectrum, some members of the Cost Effectiveness Working Group insist that all emissions should be counted. If the emissions are the result of Maryland electric consumption, whether they affect children and elderly in Maryland or Ohio or North Carolina is not important. Maryland residents (more specifically, ratepayers) may not be as willing to pay higher electricity prices to benefit people in other states, especially when other states, have long ignored Maryland pleas to reduce emissions.

Some members argued that to the extent Maryland is seen as leading by example on criteria air emissions, other upwind states could be more inclined to follow. The Healthy Air Act demonstrates Maryland's willingness to take early action on criteria pollutants. Maryland's participation in RGGI, along with a range of other climate related policies including EmPOWER, demonstrates the State's willingness to take early action on CO_2. The lead by example argument is challenged by the fact that other states emissions continue to come into Maryland despite Maryland already having some of the most stringent emissions regulations in the country. Moreover, without national and global cooperation on CO_2 emissions, investments in reducing Maryland's CO_2 emissions will be largely for naught.

Ultimately, we were unable to find agreement on the appropriate allocation of EmPOWER emissions reduction to Maryland residents. As discussed below, we applied three different percentage allocations: 10%, 50% and 100%.

2.4 Results

We estimated benefits associated with three different scenarios. These scenarios at least roughly correspond with the cases proposed by the Cost Effectiveness Working Group for the EmPOWER Potential Study.[43] The emissions benefits are provided on a discounted cents per kilowatt-hour basis and should be applied to all EmPOWER kWh savings over the lives of the

[43] Alternative scenarios may be produced upon request from the Working Group.

program measures.[44] They could be applied alone or in conjunction with other non-energy benefits.

The first scenario corresponds with the Working Groups mid-case scenario and represents our best estimate of the air emissions benefits per kWh saved by the EmPOWER programs. It is based on a 3 percent real discount rate, assumes a CO_2 damage cost of $45/ton (after RGGI allowances), and counts only 50% of CO_2 and criteria emissions.

Under this scenario, the estimated present value benefit from reduced air emissions from the EmPOWER programs would total $~~44.1~~ 79 million over the lives of the program measures. This is equal to 1.~~05~~ 1 cent~~s~~ per kWh saved by the EmPOWER programs in ~~2012~~2013. Counting air emissions benefits would have increased the statewide TRC B/C ratio to 2.~~05~~1, a ~~14~~ 16 percent increase over the preliminary B/C ratio ~~over the B/C~~ of 1.8 without air emissions benefits; program level B/C ratios would increase by the same percentage.

Table 2-10: EmPOWER Air Emissions Benefits: Enhanced Scenario

	Emissions Reductions	PV Measure Life ($)	PV Cents per kWh Saved	% Change to 2012 TRC
CO_2 (metric tons)	1,866,774 ~~1,050,086~~	50,211,684 ~~28,001,211~~	0.67 ~~0.67~~	10%~~9%~~
NOx (lbs)	1,696 ~~954~~	1,927,884 ~~1,099,517~~	0.03 ~~0.03~~	1%~~0%~~
SO_2 (lbs)	3,874 ~~2,179~~	26,672,648 ~~15,043,148~~	0.36 ~~0.36~~	6%~~5%~~
Total	NA ~~NA~~	78,812,216 ~~44,143,876~~	1.06 ~~1.05~~	16%~~14%~~
Assumptions:	*Real Discount Rate*		3.0%	
	CO_2 Price		$45	
	% Emissions Counted		50%	

The second scenario corresponds with the business as usual case of the Working Group. It is based on a 5 percent real discount rate, assumes a CO_2 damage cost of $11/ton, and counts only 10% of CO_2 and criteria emissions.

Under this scenario, the estimated present value benefit from reduced air emissions from the EmPOWER programs would total $47.5~~.3~~ million over the lives of the program measures. This

[44] If measure savings shares vary widely over time, a more accurate valuation would estimate and discount annual benefits at the measure level.

is equal to 0.1 cents per kWh saved by the EmPOWER programs in ~~2012~~2013. Counting air emissions benefits would have no material impact on the statewide or program TRC B/C ratios.

Table 2-11: EmPOWER Air Emissions Benefits: Business as Usual

	Emissions Reductions	PV Measure Life ($)	PV Cents per kWh Saved	% Change to 2012 TRC
CO_2 (metric tons)	373,355 ~~210,017~~	2,463,068 ~~1,361,634~~	0.03 ~~0.03~~	1% ~~0%~~
NOx (lbs)	339 ~~191~~	340,842 ~~196,675~~	0.00 ~~0.00~~	0% ~~0%~~
SO_2 (lbs)	775 ~~436~~	4,715,621 ~~2,696,246~~	0.06 ~~0.06~~	1% ~~1%~~
Total	NA ~~NA~~	7,519,531 ~~4,254,555~~	0.10 ~~0.10~~	2% ~~1%~~
Assumptions:	*Real Discount Rate*		5.0%	
	CO_2 Price		$11	
	% Emissions Counted		10%	

The third scenario corresponds with the aggressive case of the Working Group. It is based on a 2.5 percent real discount rate, assumes a CO_2 damage cost of $69/ton, and counts all CO_2 and criteria emissions.

Under this scenario, the estimated present value benefit from reduced air emissions from the EmPOWER programs would total $~~120~~ 212 million over the lives of the program measures. This is equal to 2.9 cents per kWh saved by the EmPOWER programs in ~~2012~~2013. Counting air emissions benefits would have increased the statewide TRC B/C ratio to 2.~~5~~6, a ~~38~~ 44 percent increase over the preliminary B/C ratio of 1.8 without air emissions benefits; program level B/C ratios would increase by the same percentage.

Table 2-12: EmPOWER Air Emissions Benefits: Aggressive

	Emissions Reductions	PV Measure Life ($)	PV Cents per kWh Saved	% Change to 2012 TRC
CO_2 (metric tons)	3,733,549 ~~2,100,173~~	153,901,459 ~~86,426,789~~	2.06 ~~2.06~~	32% ~~27%~~
NOx (lbs)	3,392 ~~1,908~~	3,981,164 ~~2,264,805~~	0.05 ~~0.05~~	1% ~~1%~~
SO_2 (lbs)	7,747 ~~4,358~~	55,080,189 ~~30,971,937~~	0.74 ~~0.74~~	11% ~~10%~~
Total	NA ~~NA~~	212,962,812 ~~119,663,531~~	2.86 ~~2.85~~	44% ~~38%~~
Assumptions:	*Real Discount Rate*		2.5%	

	CO_2 Price	$69
	% Emissions Counted	100%

2.5 Recommended Values and ~~Appropriate Benefit~~ Benefit-Cost Test

Significant Working Group discussion revolved around whether environmental externality benefits of the EmPOWER programs should be included in the Total Resource Cost Test (TRC), which is the primary test considered by the Commission, or only in the Societal Cost Test (SCT).

There are no clear rules for or against inclusion of environmental externalities in a TRC and no clear standard practice. According to ACEEE in a 2012 report, fourteen States include externality benefits in their primary benefit cost test. The SCT is the primary test in six states, while the TRC is the primary test in 29 states. That suggests that at least 8 states (14 minus 6) include externality costs in their TRC.

The Maryland Assembly, in crafting the EmPOWER ACT, clearly stated reducing the environmental impacts of electricity as an objective. If environmental benefits are a primary objective of the EmPOWER mandates and the Commission accepts that there could be costs associated with environmental improvement, it may want to incorporate them into the TRC test, which, at least to date, has been the primary test used to assess portfolio and program performance.

The EmPOWER Act distinguishes between impact on the environment and cost effectiveness, however, and at least seems to suggest that cost effectiveness should be looked at separately from environmental benefits:[45]

> *In determining whether a program or service encourages and promotes the efficient use and conservation of energy, the commission shall consider the: (i) cost–effectiveness; (ii) impact on rates of each ratepayer class; (iii) impact on jobs; and (iv) impact on the environment.*

This framing actually is congruent with arguments made by energy efficiency program advocates that energy efficiency can provide societal benefits at a "negative" cost -- i.e., that a reduction in energy consumption through improved efficiency can be procured at lower cost than the lowest cost supply resource, that even without formally considering the environmental benefits, the programs are cost effective.

[45] House Bill 374, Section 1 (A) (1).

If the intent of the Maryland Assembly was to achieve environmental benefits from energy efficiency improvements at zero or negative cost, then it could make sense to consider environmental externality costs separately from the primary TRC analysis in a separate societal or enhanced TRC benefit-cost analysis.

A notable concern about this path is that it could effectively ascribe a value of zero to the environmental damages benefits resulting from the EmPOWER programs. A 1.115 cent/kWh environmental adder was included in the Societal Cost Test (SCT) of the ex ante analysis used for the 2009-11 and 2012-14 EmPOWER program plans for four of the five of the EmPOWER utilities (PE did not include it). Aside from this adder, there has been no attempt to include environmental externality costs into the EmPOWER ex ante or ex post cost effectiveness analyses. To date, the ex post cost effectiveness analyses have not included an SCT and the ex ante SCT was not a consideration in the development and review of the previous three-year plans.

We recommend that future ex ante and ex post cost effectiveness analyses for all EmPOWER programs include a 1.1 cents ($ 2014) per kWh adder. A price inflation escalator should be applied for each year of the measure life. These values should be multiplied by the kWh saved in each year for the life of each measure to calculate the annual nominal air emissions benefits. These benefits should be multiplied by the NTG ratio for each measure or program and discounted like other benefits.

3

Comfort

3.1 Introduction

Comfort is one of the most commonly cited NEIs and is an especially important benefit for programs that include residential air sealing and insulation (i.e., shell measures). In this chapter, we apply comfort benefits used for comparable Massachusetts energy efficiency programs to two EmPOWER residential programs -- Home Performance with Energy Star (HPwES) and Limited Income. The Massachusetts comfort benefits are adapted to more closely reflect the Maryland programs' measure mix, in particular shell measures.

Comfort benefits are hard to quantify and monetize as they cannot be measured directly, and significant uncertainties exist around their estimated or self-reported dollar values. Four states in the Northeast MA, RI, DC and VT) include comfort benefits in their cost effectiveness tests.[1] California and New York only allow health, safety, and comfort impacts into the cost-effectiveness screenings for low-income programs. MA and NY have estimated comfort impacts as part of dedicated studies. CA and RI rely on secondary sources (e.g., the RI TRM uses MA estimates). Some other states (IA, CO, OR, WA, VT, DC, ID, UT, WY) include generic NEI adders of which comfort impacts may be implicitly or explicitly included. [2]

Importantly, our analysis is limited to comfort benefits, but the Massachusetts study examines a broad set of non energy impacts in Massachusetts. These other benefits should be considered for inclusion in future EmPOWER cost effectiveness analyses.

3.2 Our Methods and Assumptions

The basis for our calculations is per participant household benefits provided in a study conducted for Massachusetts[3] program administrators, conducted by Tetra Tech and Nexus Market

[1] Tim Woolf, Eric Malone, Jenn Kallay, and Kenji Takahashi, Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States, Synapse Energy Economics, prepared for the Regional EM&V Forum, October 2, 2013, p.9.

[2] Skumatz, Lisa. "Non-Energy Impacts / Non-Energy Impacts and Their Role and Values in Cost Effectiveness Tests, State Of Maryland" SERA Inc. March 2014.

[3] Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation. Tetra Tech and Nexus Market Research. August 2011.

Research, which quantified health and comfort NEIs by surveying program participants. This study surveyed 209 energy efficiency program participants and another 213 low-income program participants using a direct query method which asks participants to value impacts relative to the average bill savings for participants in the program.

The Massachusetts study estimated NEIs for specific measures, which allows us to apply them to the EmPOWER HPwES and Limited Income program measure mix. Specifically, the Massachusetts comfort benefits were ascribed to participants that made shell and/or HVAC improvements. This mapping of measures to savings was not found in any of the other studies we reviewed.

Ultimately, our decision to base our EmPOWER comfort benefits estimates on the Massachusetts study hinged on the following factors:

- It describes a plausible hypothesis for what causes non-energy impacts and thus creates monetary value to participants.
- It accounts for interactive effects between measures and makes adjustments to avoid double counting of benefits.
- It entertains the possibility that there may be costs, rather than benefits, related to the installation of energy efficiency measures.
- The sample was deemed to be robust, unbiased, and well designed.
- The study is relatively recent (2011).
- The study was performed by experienced third party consultants who are not advocates or affiliated with any advocacy groups.
- The study was reviewed by utility clients and their stakeholders before final publication.

Applying the Massachusetts comfort benefit estimates to the EmPOWER programs was straight forward. The calculations and assumptions for the HPwES programs are summarized in Table 3-1 and Table 3-2. We first converted the Massachusetts per participant benefits to 2014 dollars using the Consumer Price Index. We then multiplied the annual per participant benefit by the TRM-prescribed EUL for air sealing to arrive at the lifetime benefit per participant. The present value of the lifetime benefit was then calculated using a 5% real discount rate. As shown in Table 3-1, the estimated average PV lifetime benefit per participant installing shell measures for the HPwES program is $1,416.

Table 3-1: Comfort Benefits per Participant – HPwES

	Annual Gross Benefit per Participant MA HH (2010 $)	Annual Benefit per MA Participant HH (2014 $)	TRM-Prescribed Air Sealing EUL	Lifetime Benefit per MA Participant HH (2014 $)	PV (5%) Lifetime Benefit per MA Participant HH (2014 $)
Statewide	125	136	15.00	2,046	1,416

To show the magnitude of the impacts, for each EmPOWER utility, we then multiplied by the number of 2012 EmPOWER HPwES program shell participants and the 2012 EmPOWER HPwES NTG ratio. The final result is the estimated 2012 EmPOWER HPwES PV comfort benefits in 2014 dollars. The assumptions and sources for these various data are presented in Table 3-2 and include the 2012 EmPOWER evaluation and cost effectiveness studies and the Massachusetts study.

As shown, the statewide HPwES comfort benefits totaled $2.9 million and ranged from more than $1.9 million (PEPCO) to less than twelve thousand dollars for PE, which reported only a handful of shell participants.

Table 3-2: 2012 Comfort Benefits -- HPwES

	PV Lifetime Benefit per MA Participant HH (2014 $)	2012 EmPOWER HH Participants	2012 EmPOWER Shell Participants (%)	2012 EmPOWER NTGR	2012 EmPOWER PV Comfort Benefit (2014 $)
Statewide	1,416	**4,798**	**65%**	**0.66**	**2,917,798**
BGE		1,765	43%	0.66	713,315
PEPCO		2,329	90%	0.66	1,949,291
DPL		163	69%	0.66	105,426
SMECO		178	87%	0.63	138,255
PE		363	3%	0.69	11,511
Sources	Calc	Navigant 2012	Cadmus 2012	Navigant 2012	Calc

The calculations and assumptions for the limited income programs are summarized in Table 3-3 and Table 3-4. They are nearly identical to those of the HPwES program. The only major differences are that the Massachusetts per participant comfort benefit is lower, and the calculations are based on 2011 program activity rather than 2012 program activity. The limited income program evaluations have not been verified by Itron and Commission Staff since the 2011 program year, so it is the most recent data available.

As shown in Table 3-3, the estimated average PV lifetime benefit per participant installing shell measures for the limited income program is $1,144.

Table 3-3: Comfort Benefits per Participant – Limited Income

Limited Income	Annual Gross Benefit per MA Participant HH (2010 $)	Annual Benefit per MA Participant HH (2014 $)	TRM Prescribed Air Sealing EUL	Lifetime Benefit per MA Participant HH (2014 $)	PV (5%) Lifetime Benefit per MA Participant HH (2014 $)
Statewide	101	110	15.00	1,653	1,144

As shown in the Table 3-4, the statewide limited income program comfort benefits totaled just over $2.6 million and ranged from nearly $1.6 million (BGE) down to a little over one hundred thousand dollars for SMECO.

Table 3-4: 2011 Comfort Benefits per Participant – Limited Income

	Lifetime Benefit per MA Participant HH (2014 $)	2011 EmPOWER HH Participants	2012 EmPOWER Shell Participants (%)	2011 EmPOWER NTGR	2011 EmPOWER PV Comfort Benefit (2014 $)
Statewide	1,144	**3,550**	**64%**	**1.00**	**2,615,527**
BGE		1,868	74%	1.00	1,581,021
PEPCO		244	46%	1.00	128,374
DPL		179	52%	1.00	106,460
SMECO		110	82%	1.00	103,166
PE		1,149	53%	1.00	696,506
Sources	Calc	Navigant 2011	Navigant 2011	Navigant 2011	Calc

3.2.1 Uncertainties

While we are reasonably confident that the methods used here and in the underlying Massachusetts study accurately reflect the value placed on comfort by HPwES and limited income participants, there at least several significant sources of uncertainty with our analysis of EmPOWER comfort benefits as summarized below.

<u>Self Report Methods</u>

The Massachusetts study is based on self-reported benefits from program participants. Self-report surveys that ask participants to value NEIs are often the subject of controversy due to the inherent biases that participants may have. The accuracy of the self-report method depends on respondents providing candid and knowledgeable responses. Without revealed preference methods, however, self-report surveys are the only way to assess participant NEI values despite their biases.

Data Quality

Since comfort benefits have not been considered in the EMPOWER evaluations or cost effectiveness analyses to date, we had to cobble data pertaining to participation, shell and HVAC measures from a variety of sources. The quality of the various data can be vastly improved if it is collected and reported as part of the other evaluation and cost effectiveness data requests. If the comfort benefit is used in future ex ante and/or ex post cost effectiveness analysis, as we recommend, Itron will provide clear guidance to utilities and contractors about the data that is needed.

Application of Massachusetts Study Benefits to Residential HVAC

The MA study estimated participant household comfort benefits for shell improvements, HVAC improvements, and shell and HVAC improvements combined. We applied the MA Study per participant benefit to all HPwES and limited income participants that implemented shell measures. We did not apply the comfort benefit to the residential HVAC program.

The EmPOWER residential HVAC evaluation generally assumes that new efficient HVAC systems are purchased in lieu of alternative standard efficiency units (e.g., SEER 13 central air conditioners); the incentives provided by the programs are not considered sufficient to drive replacement of HVAC systems with any significant remaining life. While Massachusetts HVAC program respondents reported comfort benefits, we are unclear how a new energy efficient HVAC unit would provide significantly greater "comfort" than a new standard efficiency unit. We suspect that MA survey respondents could have been comparing the comfort of their new efficient units to the units that were replaced.

It is also possible that the Massachusetts survey respondents were ascribing greater comfort to the efficient unit because the lower operating costs will allow them to run the unit more frequently or at different set temperatures (i.e., there is a rebound effect). If so, the comfort benefit would be at least partially offset by increased energy consumption and lower energy savings benefits for the program. If the program impact evaluation included pre/post or billing data analysis, then the energy savings (or lack thereof) would have been accounted for and then comfort benefits should be included. The EMPOWER residential HVAC program evaluation has never included a bill analysis, however. To the extent that a rebound effect is occurring, the evaluated energy savings are likely overstated and hence comfort benefits should not be included.

3.3 Results and Application

In this section we summarize the results of our analysis and provide recommendations for their application to the EmPOWER ex ante and ex post cost effectiveness analyses.

We recommend that Massachusetts comfort benefits of $136 and $110 should be applied, respectively, for every HPwES and limited income participant for which air sealing and/or insulation measures are installed as a result of the program (i.e., after adjusting for free ridership and spillover). The values should be applied annually for 15 years. These values are in 2014 dollars and should be escalated by the inflation rate used in the analysis.

These benefits should be added to other discounted electric and non-electric benefits in the TRC and SCT (and the participant cost test if it is estimated for future EMPOWER program cycles). For the MEA potential study, we offer a straw man propose that 25% of the values be applied for the low case and 150% of the value be applied to the high case, but must point out that these adjustment percentages are arbitrarily selected and we would defer to the MEA Cost Effectiveness Working Group on these ranges.

Table 3-5 and Table 3-6 below report the impacts on the TRC benefit cost ratios if the recommended comfort benefits had been included in the 2012 HPwES and the 2011 limited income program cost effectiveness analyses.

As shown in Table 3-5, the comfort benefits would have increased the statewide TRC B/C ratio for the HPwES programs from 0.6 to 0.79. While a significant boost to the programs, it would not in itself have made any of the utilities programs cost effective. The PEPCO TRC would have received the greatest boost from including the comfort benefit and would have come close to passing the TRC.

Table 3-5: Comfort Benefits Impact on EmPOWER HPwES Program Cost Effectiveness

	2012 PV Comfort Benefit (2014 $)	2012 TRC PV Benefits (2014 $)	2012 TRC B/C Ratio	Rev 2012 TRC BC Ratio	2012 Net Lifetime MWH Savings	2012 PV Comfort Benefit Cents per Net kWh Saved
Statewide	**2,917,798**	**9,117,856**	**0.6**	**0.79**	**55,335**	**5.27**
BGE	713,315	4,510,180	0.7	0.81	24,960	2.86
PEPCO	1,949,291	3,713,344	0.59	0.90	22,740	8.57
DPL	105,426	443,091	0.46	0.57	2,745	3.84
SMECO	138,255	356,046	0.52	0.72	1,800	7.68
PE	11,511	95,197	0.11	0.12	3,090	0.37

As shown in Table 3-6, the comfort benefits would have increased the statewide TRC B/C ratio for the limited programs from 0.55 to 0.69. As with the HPwES programs, the comfort benefit would significantly increase the limited income program TRC B/C results, but it would not in itself have made any of the utilities programs cost effective. The PE TRC would have doubled. For both BGE and PE, the TRCs would have come much closer to passing the TRC.

Table 3-6: Comfort Benefits Impact on EmPOWER Limited Income Program Cost Effectiveness

	2011 PV Comfort Benefit (2014 $)	2011 TRC PV Benefits (2014 $)	2011 TRC BC	Rev 2011 TRC BC	2011 Net Lifetime MWH Savings	2011 PV Comfort Benefit Cents per Net kWh Saved
Statewide	**2,615,527**	**10,212,779**	**0.55**	**0.69**	**831,810**	**0.31**
BGE	1,581,021	6,664,950	0.65	0.80	730,425	0.22
PEPCO	128,374	902,160	0.36	0.41	28,665	0.45
DPL	106,460	1,448,212	0.60	0.64	4,320	2.46
SMECO	103,166	513,195	0.30	0.36	50,055	0.21
PE	696,506	684,262	0.38	0.77	18,345	3.80

4

O&M Benefits from EmPOWER Commercial & Industrial Programs

4.1 Introduction

In this chapter, we examine the magnitude and potential methods for estimating operation and maintenance (O&M) benefits resulting from investments promoted by the EmPOWER Commercial and Industrial (C&I) Prescriptive and Small Business Direct Install (SBDI) programs. We provide a bottom-up engineering estimation of the O&M benefits associated with occupancy sensors and lamp replacements, which are the single largest source of O&M benefits for these programs based on the analysis presented here. Data limitations precluded estimation of some other O&M benefits and we chose not to use other O&M benefits from HVAC and Variable Frequency Drive (VFD) measures that are commonly cited in the literature; these issues are discussed below. The lighting measures included in our benefit estimates comprise 71 percent and 77 percent, respectively, of the total Prescriptive and SBDI kWh savings and similarly large shares of measure unit quantities.

Including the benefits from avoided C&I lamp replacement and occupancy sensor maintenance would give a modest boost to the cost effectiveness of the C&I programs.[1] Below, we describe our analytical methods and data, provide estimates of the O&M benefits from avoided lamp replacement, assess the impacts of including these benefits on 2013 TRC benefit cost ratios, and offer recommendations for how these estimates should be applied in future ex post and ex ante cost effectiveness analyses.

4.2 Methods and Data

At a high level, our analysis consisted of the following seven steps for each of the five utilities C&I programs:

1) Literature Survey
2) Identify priority measures
3) Establish conceptual basis for O&M benefits associated with the priority measures

[1] These benefits are not currently included in cost effectiveness analysis of commercial measures.

4) Develop algorithm for calculating the per-unit lamp replacement benefits
5) Estimate or source input parameter values
6) Calculate the measure-level benefits
7) Estimate impact of lamp replacement benefits on utility program-level TRC benefit cost estimates

Each of these steps is discussed below.

4.2.1 Literature Survey

The first step in our analysis was to identify key O&M benefits studies that could provide methodological insights or results that could be applicable to the EmPOWER programs. Few studies have rigorously attempted O&M benefits estimates at least in recent years. The Mid-Atlantic TRM prescribes lamp replacement benefits for the residential and C&I lighting measures.[2] Far and away the most comprehensive study we found was a Massachusetts Non-Energy Impacts study published in July 2012.[3] We reviewed other studies, but the TRM and Massachusetts studies were the only ones published in the last decade that contained original analysis (as opposed to summaries of other studies) and whose methods we thought might be sufficiently rigorous and transparent to be able to apply them to the EmPOWER programs.[4]

Upon further consideration, we determined that the O&M benefits estimates from these sources should not be used for the EmPOWER estimates because of a potential mismatch between baselines used by program participants to estimate energy and non-energy benefits. The methods and discussions in these studies did help inform our analysis and the Massachusetts study, in particular, could inform future broader based- studies of EmPOWER C&I O&M benefits.

<u>Mid-Atlantic Technical Resource Manual</u>

The Mid-Atlantic TRM prescribes lamp replacement cost savings values associated with residential and C&I lighting measures, which are based on engineering based calculations. The

[2] Northeast Energy Efficiency Partnership. Technical Reference Manual, Version 4.0, prepared by Shelter Analytics, June 2014. Other state and regional TRMs include lamp replacement cost benefits, but as a member of the Mid-Atlantic TRM Advisory Group, Itron had access to the background calculations.

[3] Tetra Tech, DNV GL, Final Report – Commercial and Industrial Non-Energy Impacts Study, prepared for the Massachusetts Program Administrators, June 29, 2012.

[4] Other studies we reviewed include: Roth, Johna and Nick Hall, *Non-Electric Benefits from the Custom Projects Program: A Look at the Effects of Custom Projects in Massachusetts*, TecMarket Works, prepared for: National Grid, September 25, 2007; Skumatz, Lisa A., Ph.D., Sami Khawaja, Jane Colby, *Lessons Learned and Next Steps in Energy Efficiency Measurement and Attribution: Energy Savings, Net to Gross, Non-Energy Benefits, and Persistence of Energy Efficiency Behavior*, Skumatz Economic Research Associates, prepared for California Institute for Energy and Environment (CIEE) Behavior and Energy Program, Berkeley, CA, November 2009; and Mosenthal, Phil and Matt Socks, *Non-Electric Benefits Analysis Update*, Optimal Energy, Inc., D.P.U. 09-119, Attachment AG-1-22 (j), November 7, 2008.

TRM does not include O&M benefits associated with occupancy sensors. The TRM is the default source for parameter inputs and algorithms in the EmPOWER impact evaluations and cost effectiveness analyses. The TRM is updated annually by NEEP with support from numerous advisory group members from states throughout the Mid-Atlantic region, including Maryland.

As the default document for the EMPOWER evaluations and cost effectiveness analyses, we considered using or adapting the prescribed values in the TRM to estimate lamp replacement benefits. However, in our review of the prescribed values, we identified some problems with the assumptions and calculations, which were confirmed in follow up discussions with the TRM authors.[5] While some of the methods were instructive, we ultimately determined to independently recalculate the lamp replacement cost savings.

Massachusetts Non-Energy Impact Study

The Massachusetts study is based on self report surveys of 1,499 program year 2010 prescriptive program participants and more than 258 custom program participants. It examined thirteen NEI types across six major measure types. The large study sample enabled the authors to develop statistically significant estimates for many of those measure categories and NEIs for both custom and prescriptive programs, as presented in the tables below.[6]

Table 4-1: Massachusetts Study Gross Annual Non-Energy Impacts per kWh – Prescriptive Electric

NEI Reporting Category	n	Average NEI	NEI/kWh	90% CI Low	90% CI High	% of Population kWh	Stat Sig
HVAC	27	$7,687	$0.0966	$0.0544	$0.1389	8%	Yes
Lighting	163	$1,636	$0.0274	$0.0176	$0.0372	69%	Yes
Motors and Drives	50	$541	$0.0043	($0.0005)	$0.0091	18%	No
Refrigeration	30	$5	$0.0013	($0.0002)	$0.0028	0%	No
Other	32	$28	$0.0039	($0.0002)	$0.0079	3%	No
Overall	**302**	**$1,439**	**$0.0274**	**$0.0188**	**$0.0360**	**100%**	**Yes**

[5] Itron will work with the TRM authors and Advisory Group to make necessary adjustments to these values as part of the 2015 (version 5) update).

[6] The Massachusetts study does not discuss the applicability of Prescriptive program results to SBDI programs.

Table 4-2: Massachusetts Distribution of Gross Annual Non-Energy Impacts by Category – Prescriptive Electric

NEI Reporting Category	Admin	Fees	Material Handling	Material Movement	Other Costs	Other Labor	O&M	Other Revenue	Product Spoilage	Rent Revenue	Sales Revenue	Waste Disposal	Total Impacts
HVAC	8.2%*	0.00%	0.00%	0.00%	3.40%	-0.30%	69.8%*	0.00%	0.00%	18.90%	0.00%	0.00%	100.0%*
Lighting	5.0%*	0.00%	2.9%*	0.40%	0.00%	7.30%	73.7%*	0.00%	0.00%	0.00%	8.30%	2.3%*	100.0%*
Motors and Drives	0.6%*	0.00%	0.0%*	0.0%*	4.90%	0.20%	94.80%	0.00%	0.00%	0.00%	-0.50%	0.0%*	100.00%
Refrigeration	0.0%*	0.00%	0.0%*	0.0%*	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.0%*	100.00%
Other	1.00%	0.00%	0.0%*	0.0%*	0.00%	0.00%	99.00%	0.00%	0.00%	0.00%	0.00%	0.0%*	100.00%
Overall	**5.4%***	**0.00%**	**2.4%***	**0.40%**	**0.60%**	**6.10%**	**73.5%***	**0.00%**	**0.00%**	**2.80%**	**6.90%**	**2.0%***	**100.0%***

Significance = *

Table 4-3: Massachusetts Study Gross Annual Non-Energy Impacts per kWh – Custom

NEI Reporting Category	n	Average NEI	NEI/kWh	90% CI Low	90% CI High	% of Population kWh	Stat Sig
CHP/Cogen	6	($12,949)	($0.0147)	($0.0247)	($0.0047)	11%	Yes
HVAC	20	$5,584	$0.0240	$0.0003	$0.0477	28%	Yes
Lighting	89	$5,686	$0.0594	$0.0318	$0.0871	25%	Yes
Motors and Drives	42	$1,433	$0.0152	($0.0005)	$0.0309	10%	No
Refrigeration	90	$1,611	$0.0474	$0.0244	$0.0705	8%	Yes
Other	29	$15,937	$0.0562	$0.0038	$0.1087	18%	Yes
Overall	**276**	**$4,454**	**$0.0368**	**$0.0231**	**$0.0506**	**100%**	**Yes**

Table 4-4: Massachusetts Distribution of Gross Annual Non-Energy Impacts by Category – Custom

NEI Reporting Category	Admin	Fees	Material Handling	Material Movement	Other Costs	Other Labor	O&M	Other Revenue	Product Spoilage	Rent Revenue	Sales Revenue	Waste Disposal	Total Impacts
CHP/Cogen	20.3%*	0.00%	0.00%	0.00%	0.00%	0.00%	79.7%*	0.00%	-0.0%*	0.00%	0.00%	-0.0%*	100.0%*
HVAC	6.10%	0.00%	0.00%	0.00%	9.60%	7.70%	70.80%	0.00%	2.00%	3.80%	0.00%	0.0%*	100.0%*
Lighting	5.2%*	0.00%	0.20%	0.40%	13.20%	0.0%*	79.7%*	0.00%	0.0%*	0.00%	0.1%*	1.2%*	100.0%*
Motors and Drives	1.40%	0.00%	0.00%	0.00%	0.00%	0.0%*	68.7%*	0.00%	29.90%	0.00%	0.00%	0.0%*	100.00%
Refrigeration	0.00%	0.00%	2.60%	0.00%	0.00%	0.0%*	55.8%*	0.00%	41.6%*	0.00%	0.00%	0.0%*	100.0%*
Other	0.00%	0.00%	0.00%	0.00%	0.00%	14.80%	-41.60%	0.00%	6.10%	0.00%	120.60%	0.10%	100.0%*
Overall	**2.40%**	**0.00%**	**0.40%**	**0.20%**	**7.60%**	**5.4%***	**40.80%**	**0.00%**	**7.8%***	**0.60%**	**34.30%**	**0.6%***	**100.0%***

Significance = *

We considered applying the results from the Massachusetts Non-Energy Impacts study to the EmPOWER programs, but ultimately decided not to use the MA study for several reasons. First, we were unable to get sufficiently granular information about individual lighting measures. Since 2010, the program year upon which the study is based, federal standards which prohibit the manufacture of most T12 lamps, have radically changed the lighting marketplace. The EmPOWER C&I lighting programs, like C&I programs in other states, are evolving in response to these new standards. Aside from CFLs, there are three major measure types:

1) Replacing T12s with standard T8s,
2) Replacing standard T8s with high performance T8s, and
3) Replacing fluorescent lamps with LED lamps.

Replacing standard T8s with high performance T8s will provide a much smaller O&M benefit than replacing T12s with T8s because the differences between measure and baseline EULs are smaller. Replacing fluorescents with LEDs will provide a much larger benefit. To the extent that Massachusetts program participants surveyed in 2010 were referring to early replacement of replacement of older T12 systems, their estimated O&M benefits would be too high to apply to current and future programs. Without knowing the individual lighting measures in the 2010 MA portfolio or more precisely the types of lighting configurations that the survey respondent were referencing, we had no way to adjust the Massachusetts study O&M estimates to reflect the EmPOWER program measure mix.

Second, we were unclear about what was driving the MA Study results for some of the measure benefits. For example, as shown in

Table 4-4 above, the custom program "Other" measure category "O&M" benefit was highly negative while "Sales Revenues" were highly positive. We suspected, but were unable to verify, that this project involved expanded production; we cannot otherwise see how this measure would offer such a high additional O&M costs and additional sales revenue.[7] If the project involved expanded production, however, the baseline for comparison should be the standard efficiency equipment that would have been purchased, not the *in situ* condition in which there was no expanded production.

Another measure benefit that gave us pause was the prescriptive program HVAC, which was nearly 10 cents per kWh. We suspected this high value was driven by survey respondents comparing their *in situ* units to the new efficient units, rather than comparing a new standard efficiency to the new high efficiency model. Our review of the survey O&M battery found no clear guidance for respondents to compare to the equipment they purchased to the equipment they would have purchased if not for the program incentive. And the formulas that were reportedly used to estimate the benefits associated with these measures compares the new systems to the old *in situ* systems, rather than the systems that would have been purchased.[8]

If the replacement of the *in situ* HVAC units was induced by the program, then the comparisons between the in situ and new efficient units would be appropriate. But program incentives are typically set at levels that induce purchase of high efficiency units rather than standard units. The program incentive would have to be extremely large to induce replacement of an existing system that was not going to be replaced anyway. To be able to apply the MA study HVAC values to EmPOWER, we would need, at minimum, separate values for HVAC early replacements versus HVAC end of life replacements. This information was not available from the study authors. [9]

While we ultimately decided against using the Massachusetts study for our O&M benefits estimates, it employed best practice methods and could serve as a model for a more ambitious analysis of EmPOWER C&I non-energy impacts in the future.

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[7] In phone correspondence Massachusetts study lead author June 25, 2014, he said he could not say definitely what was causing the negative O&M nor the 120% "sales revenue" increase for the Custom "Other" measure category. He said they did everything they could to ensure no double counting – i.e., that the "increased sales revenue" benefit was net of cost of production. He also emphasized the study was intended to look at total NEIs and not the underlying NEI components.

[8] Tetra Tech, DNV GL, Final Report – Commercial and Industrial Non-Energy Impacts Study, prepared for the Massachusetts Program Administrators, June 29, 2012, Table 3-7, p. 3-23

[9] Phone correspondence Massachusetts study lead author June 25, 2014

4.2.2 Identify Priority Measures

We calculated kWh, kW and unit shares for all C&I Prescriptive and SBDI program measures to prioritize measure types. As shown in Table 4-5 and Table 4-6, lighting measures comprised the vast majority of kWh savings. Motors & VFDs were a distant second, driven by PEPCO and DPL. Other measures include refrigeration, building shell, and cooking measures.

Among the lighting measures, there were five major types: 1) linear fluorescent lighting, 2) interior LEDs, 3) exterior LEDs, 4) occupancy sensors, and 5) CFLs (SBDI only).[10] These measures, which are the measures we included in our O&M benefits estimates, comprise 71 percent of Prescriptive and 77 percent of SBDI kWh savings.

Table 4-5: 2013 Measure Percentage Shares of Total Reported Savings – Prescriptive

Utility	4 Major Lighting Measures*	Lighting	Motors & VFD	HVAC	Other	Total kWh
BGE	76%	82%	7%	1%	10%	88,318,086
PEPCO	56%	71%	19%	0%	11%	41,983,816
DPL	62%	86%	9%	0%	5%	9,538,556
SMECO	79%	82%	1%	1%	16%	4,356,341
PE	82%	84%	1%	0%	15%	18,769,096
Total	**71%**	**80%**	**9%**	**0%**	**11%**	**162,965,895**

* Includes linear fluorescent lighting, interior LEDs, exterior LEDs, and occupancy sensors.

Table 4-6: 2013 Measure Percentage Shares of Total Reported Savings – SBDI

Utility	5 Major Lighting Measures*	Lighting	Motors & VFD	HVAC	Other	Total
BGE	81%	91%	3%	3%	3%	37,186,106
PEPCO	79%	93%	0%	0%	7%	52,973,388
DPL	74%	91%	0%	0%	8%	14,852,340
SMECO	95%	100%	0%	0%	0%	1,549,704
PE	0%	12%	0%	0%	88%	2,202,276
Total	**77%**	**90%**	**1%**	**1%**	**8%**	**108,763,815**

* Includes CFLs, linear fluorescent lighting, interior LEDs, exterior LEDs, and occupancy sensors.

[10] Other lighting measures include exit signs, daylighting controls, and LED case lights.

4.2.3 Establish Conceptual Basis for O&M Benefits Associated with the Priority Measures

Based on our literature survey, we inventoried and assessed the potential significant sources of O&M benefits (and costs) associated with the priority lighting, HVAC and VFD measures. For various reasons discussed below, we concluded that the predominant O&M benefits for lighting are associated with avoided lamp replacement costs and avoided labor costs associated with switching off lights as a result of installing occupancy sensors.

As discussed below, we considered and ultimately decided against including O&M benefits associated with EMPOWER C&I program HVAC and VFD measures.

Lighting

Two major types of O&M benefits apply to lighting systems. First, costs associated with lamp replacement can be avoided as a result of installing high efficiency lighting systems. Specifically, LED lamps have longer lives than high efficiency T8s, which have longer lives than standard T8s, which have longer lives than T12s. The relative lamp replacement costs depend on the frequency of lamp replacement, the unit prices of the lamps, and the labor required to install them.

Second, occupancy sensors could provide additional lighting O&M benefit if building maintenance personnel avoid walking through buildings to switch lights on or off. We initially were reluctant to include these occupancy sensor maintenance cost benefits since the basis for energy savings from occupancy sensors is that maintenance staff do NOT spend time turning off lights. You can either claim energy savings or O&M savings, but to count both would be double dipping.[11] However, the Maryland evaluation and the Mid-Atlantic TRM only count 28% of energy and 14% of demand associated with the lighting systems attached to the sensors.[12] And those lighting systems energy and demand impacts are calculated using assumed business hours of use, which implicitly assumes that someone is turning off the lights outside of business hours.

We also were initially concerned about offsetting maintenance costs associated with occupancy sensors, for tuning and repairs that would not occur with a normal flip switch. While these offsetting costs do exist, we decided they were likely small compared to the daily labor costs associated with turning lights off at night.

[11] This view was also expressed by Bret Hamilton, Shelter Analytics, in email correspondence July 25, 2014.

[12] Northeast Energy Efficiency Partnership. Technical Reference Manual, Version 4.0, prepared by Shelter Analytics, June 2014. p.261.

HVAC

HVAC O&M benefits would be realized to the extent a new efficient HVAC system incurs fewer repair and maintenance costs than the baseline system. In general, we would expect a new system to require fewer repairs than the in situ system that was replaced. If the HVAC equipment was replaced before the end of its useful life (i.e., was a "retrofit") and the program incentives induced the replacement, then the O&M benefits could be significant. If the in situ system was at the end of its useful life, however, then the benefits would be much smaller, since the relevant comparison would be between the new purchased high efficiency system and the alternative system that would have been replaced if the program did not exist.

We considered including O&M benefits associated with HVAC measures, but decided against it. The main reason was that it is difficult to distinguish between a retrofit HVAC unit and a replace on burnout unit and, as noted above, we were unclear how a new energy efficient HVAC unit would incur significantly lower O&M costs than a new standard efficiency unit. It is unclear whether the incentives provided by the custom programs are sufficient to drive replacement of HVAC systems with any significant remaining life; the default EmPOWER evaluation assumption is that the new efficient HVAC systems are purchased in lieu of alternative standard efficiency units (e.g., SEER 13 central air conditioners).

A secondary reason for not including HVAC measures is that the data were not readily available to allow us to develop O&M benefit estimates for the wide range of HVAC measures incentivized through the EmPOWER programs. In future years, HVAC measures should be given further consideration.

VFDs

O&M benefits are frequently ascribed to VFDs. These benefits are related to the "soft start" capability that VFDs provide. Without VFDs, single-speed motors start abruptly which subjects a motor to very high torque and current surges. A VFD can gradually ramp up the motor to operating speed - hence "soft start." A soft start lessens mechanical and electrical stress on the motor system, which should in theory reduce maintenance and repair costs and extend motor life.

Because VFDs are solid-state devices, increased O&M costs for the VFD units themselves are likely to be non-existent or minimal. However, VFDs can increase harmonic distortion, which could adversely affect power quality and increase maintenance costs associated with other machinery. The additional electrical connections needed, and for some applications the need for a bypass device in the case of VFD unit failure, are also possible O&M issues.

Our conclusion, based on the experience of Itron engineers is that the significant advantages of energy savings and improved process control will far outweigh any peripheral O&M benefits or costs from VFDs. Furthermore, we are not aware of any references that provide quantitative estimates of the O&M impacts associated with VFDs. Consequently, we did not attempt to include VFD O&M benefits in this analysis. In future years, VFDs should be given further consideration.

4.2.4 Develop Algorithms for Calculating the Per-Unit Lamp Replacement Benefits

The calculations used for this analysis are straightforward.[13] The lamp replacement benefits equal the discounted stream of costs associated with baseline lamp replacement minus the discounted stream of costs associated with measure lamp replacement (the base case assumes a 5-percent real discount rate). Lamp replacement savings were calculated with and without labor costs.

The streams of lamp replacement costs were counted over the life of the program measures. For example, C&I programs provide incentives for linear fluorescent fixtures, not linear lamps; thus the annual costs of measure and baseline linear lamp replacements are summed over the measure fixture life. By contrast, where the program measure is the lamp itself (e.g., CFLs and some LEDs), the annual costs of the baseline lamp replacement are summed over the measure lamp life.

The discounted lifetime benefit per lighting measure was multiplied by the number of corresponding measures for each utility. This gave the discounted lamp replacement benefit for each utility program.

Occupancy sensor cost savings result from reduced labor costs. We assumed one minute per day of maintenance staff time per sensor. We then assumed that one minute would be saved 300 days per year, thus totaling five hours per year. We then multiplied by the maintenance wage rate to get annual labor cost. The annual labor cost per sensor was summed over the estimate useful life of an occupancy measure and discounted to calculate the discounted lifetime benefit per sensor. The discounted lifetime benefit per sensor was multiplied by the number of program occupancy sensors installed in each utility program to arrive at the discounted program benefit.

4.2.5 Estimate or Source Input Parameter Values

The most challenging part of this analysis was developing the key parameters required to estimate lamp replacement costs, including: the number of calendar year 2013 program fixtures or lamps, the number of lamps per fixture, measure and baseline lamp prices, measure and baseline EULs, lamp replacement labor hours and wage rates. Development of these parameter

[13] Background calculations are available upon request.

inputs required scrutiny of utility tracking data to develop typical lighting systems that were consistent with tracking system weighted average savings for each measure type.

The sources and methods used to develop each of the parameter assumptions are described in detail below. We were able to develop estimates for all of the utilities' Prescriptive programs and all but PE's SBDI program; the PE SBDI tracking data was not sufficiently detailed to allow us to estimate incandescent replacement costs or occupancy sensors O&M benefits.

Development of the occupancy sensor input parameter was far less involved since it is a relatively uniform and well defined measure.

All parameter assumptions and sources are summarized in Table 4-7.

Table 4-7: Parameter Assumptions and Sources

Labor Costs				
Measure Type	**Labor Hours**	**MD Wage Rate**	**Cost per Replacement**	**Sources**[14]
CFL ROB	0.08	$19.22	$1.54	Labor hours from Itron Measure Cost Study measure name: CFL A-Lamps and Twisters. Hourly Wage Rate from BLS for Maryland Maintenance Worker.
Linear Fluorescent Fixture ROB	0.4	$19.22	$7.69	Labor hours from Efficiency Vermont TRM (p.127) for "T8 3L-F32 w/Elec - 4'" fixture." Hourly Wage Rate from BLS for Maryland Maintenance Worker.
Interior LED ROB	0.13	$19.22	$2.56	Labor hours from Efficiency Vermont TRM (p.127) for "Recessed, Surface, Pendant Downlights." Hourly Wage Rate from BLS for Maryland Maintenance Worker.
Exterior LED ROB	0.13	$19.22	$2.56	Labor hours from Efficiency Vermont TRM (p.127) for "LED Wall Mounted Area Lights." Hourly Wage Rate from BLS for Maryland Maintenance Worker.
Occupancy Sensor	1.25	$19.22	$24.03	Assumes each sensor saves 15 seconds per day of maintenance staff time. Assuming 300 annual work days, that equates to 75 minutes (or 1.25 hours) per year. Hourly Wage Rate from BLS for Maryland Maintenance Worker.
Replacement Lamp Costs				
Measure Type	**Measure Lamp Cost**	**Baseline Lamp Cost**		**Sources**

[14] BLS Maintenance and Repair Workers (#49-9071) – Perform work involving the skills of two or more maintenance or craft occupations to keep machines, mechanical equipment, or the structure of an establishment in repair. Duties may involve pipe fitting; boiler making; insulating; welding; machining; carpentry; repairing electrical or mechanical equipment; installing, aligning, and balancing new equipment; and repairing buildings, floors, or stairs. Excludes "Maintenance Workers, Machinery" (49-9043).

CFL ROB	NA	$1.40		Mid-Atlantic Technical Resource Manual, p.235. TRM value is based on Itron Measure Cost Study, Appendix F, p.13. Assumes CFL replacing 60W halogen incandescent.
Linear Fluorescent Fixture ROB	$23.01	$15.51		Average measure fixture in BGE SBDI and Prescriptive tracking systems contains 3 lamps, so costs multiplied by 3. Mid-Atlantic Technical Resource Manual, p.243. TRM values adapted from Efficiency Vermont Technical Reference Manual 2013-82.5, August 2013.
Interior LED ROB	NA	$9.88		Mid-Atlantic Technical Resource Manual, p.253. Assumes 40% CFLs at $9.70 each and 60% Halogen Par 30-38 lamps at $10 each.
Exterior LED ROB	NA	$28.00		Efficiency Vermont TRM, http://www.greenmountainpower.com/upload/photos/371TRM_User_Manual_No_2013-82-5-protected.pdf, p. 127. Assumes 175W pole mounted HID for parking/roadway replaced by 30W-70W LED.
Annual HOU				
Measure Type	**HOU**			**Sources**
SBDI CFL ROB	2,632			HOU equals CFL lamp life divided by weighted average EUL from BGE SBDI tracking system. CFL lamp life from Mid-Atlantic Technical Resource Manual: 10,000 hours.
SBDI Linear Fluorescent Fixture ROB	3,257			HOU = Lamp life / Weighted average EULs from BGE SBDI tracking system. Lamp life from Mid-Atlantic Technical Resource Manual: 35,000 hours for measure lamp, 20,000 for baseline lamp.
SBDI Interior LED ROB	3,830			HOU is from Mid-Atlantic Technical Resource Manual, Appendix D, p.347. Based on EmPOWER Maryland DRAFT Final Impact Evaluation Report Evaluation Year 4 (June 1, 2012 – May 31, 2013) Commercial & Industrial Prescriptive & Small Business Programs, Navigant, March 31, 2014
SBDI Exterior LED ROB	4,737			Weighted average annual HOU from BGE SBDI tracking data.
Prescriptive Linear Fluorescent Fixture ROB	3,257			HOU = Lamp life / Weighted average EULs from BGE Prescriptive tracking system. Lamp life from Mid-Atlantic Technical Resource Manual: 35,000 hours for measure lamp, 20,000 for baseline lamp.
Prescriptive Interior LED ROB	3,830			HOU is from Mid-Atlantic Technical Resource Manual, Appendix D, p.347. Based on EmPOWER Maryland DRAFT Final Impact Evaluation Report Evaluation Year 4 (June 1, 2012 – May 31, 2013) Commercial & Industrial Prescriptive & Small Business Programs, Navigant, March 31, 2014
Prescriptive Exterior LED ROB	6,208			Weighted average annual HOU from BGE Prescriptive tracking data.
Estimated Useful Life				

Measure Type	Measure Lamp EUL	Baseline Lamp EUL	Measure EUL	Sources
SBDI CFL ROB	3.80	0.38	3.80	Measure EUL = weighted average annual EUL from BGE SBDI tracking data. Baseline EUL = 1,000 hour lamp life / annual HOU.
SBDI Linear Fluorescent Fixture ROB	11.00	6.14	15.00	Measure Lamp is the weighted averages from BGE SBDI tracking system. Baseline Lamp EUL = Lamp life of 20,000 hours/annual HOU. Fixture life from Mid-Atlantic Technical Resource Manual, p.242.
SBDI Interior LED ROB	9.00	1.44	9.00	Baseline lamp EUL = 5,500 lamp hour life / annual HOU for "other" building type from TRM (347). Baseline lamp hour life is based on prescribed TRM (p.253) prescribed 60/40 split between Par lamps with 2,500 hour EUL and CFLs with 10,000 hour EUL. Measure lamp life = 35,000 hour life / annual HOU for "other" building type from TRM (347).
SBDI Exterior LED ROB	13.00	2.11	13.00	Lamp EUL is the weighted average of EUL from BGE SBDI Tracking data. Lamp life from Mid-Atlantic Technical Resource Manual: 10,000 hour HID lamp life (p.282); 70,000 hour LED lamp life (p.280). Annual weighted average HOU from BGE SBDI tracking data.
SBDI Occupancy Sensor	NA	NA	10.00	Mid-Atlantic Technical Resource Manual, p.263.
Prescriptive Linear Fluorescent Fixture ROB	10.75	6.14	15.00	Measure Lamp EUL is the weighted average from BGE SBDI tracking system. Baseline Lamp EUL = Lamp life of 20,000 hours/annual HOU. Fixture life from Mid-Atlantic Technical Resource Manual, p.242.
Prescriptive Interior LED ROB	9.00	1.44	9.00	Baseline lamp EUL = 5,500 lamp hour life / annual HOU for "other" building type from TRM (347). Baseline lamp hour life is based on prescribed TRM (p.253) prescribed 60/40 split between Par lamps with 2,500 hour EUL and CFLs with 10,000 hour EUL. Measure lamp life = 35,000 hour life / annual HOU for "other" building type from TRM (347).
Prescriptive Exterior LED ROB	13.59	1.61	13.59	Lamp EUL is the weighted average of EUL from BGE SBDI Tracking data. Lamp life from Mid-Atlantic Technical Resource Manual: 10,000 hour HID lamp life (p.282); 70,000 hour LED lamp life (p.280). Annual weighted average HOU from BGE SBDI tracking data.
Prescriptive Occupancy Sensor	NA	NA	10.00	Mid-Atlantic Technical Resource Manual, p.263.
SMECO SBDI Linear Fluorescent Fixture ROB	11.00	6.14	15.00	Measure Lamp EUL is the weighted average from SMECO SBDI tracking system. Baseline Lamp EUL = Lamp life of 20,000 hours/annual HOU. Fixture life from Mid-Atlantic Technical Resource Manual, p.242.

SMECO SBDI Interior LED ROB	12.40	1.44	12.40	Baseline Lamp EUL = 5,500 lamp hour life / annual HOU for "other" building type from TRM (347). Baseline lamp hour life is based on prescribed TRM (p.253) prescribed 60/40 split between Par lamps with 2,500 hour EUL and CFLs with 10,000 hour EUL. Measure lamp life = 35,000 hour life / annual HOU for "other" building type from TRM (347).
SMECO Prescriptive Linear Fluorescent Fixture ROB	10.10	6.14	15.00	Measure Lamp EUL is the weighted average from SMECO SBDI tracking system. Baseline Lamp EUL = Lamp life of 20,000 hours/annual HOU. Fixture life from Mid-Atlantic Technical Resource Manual, p.242.
SMECO Prescriptive Interior LED ROB	8.98	1.44	8.98	Baseline Lamp EUL = 5,500 lamp hour life / annual HOU for "other" building type from TRM (347). Baseline lamp hour life is based on prescribed TRM (p.253) prescribed 60/40 split between Par lamps with 2,500 hour EUL and CFLs with 10,000 hour EUL. Measure lamp life = 35,000 hour life / annual HOU for "other" building type from TRM (347).
SMECO Prescriptive Exterior LED ROB	13.11	1.61	13.11	Measure Lamp EUL is the weighted average of EUL from SMECO SBDI Tracking data. Lamp life from Mid-Atlantic Technical Resource Manual: 10,000 hour HID lamp life (p.282); 70,000 hour LED lamp life (p.280). Annual weighted average HOU from SMECO SBDI tracking data.
SMECO Prescriptive Occupancy Sensor	NA	NA	10.00	Mid-Atlantic Technical Resource Manual, p.263.

Sources	
Mid-Atlantic Technical Resource Manual	Northeast Energy Efficiency Partnership. Technical Reference Manual, Version 4.0, prepared by Shelter Analytics, June 2014.
Efficiency Vermont TRM	**Error! Hyperlink reference not valid.**
Itron Ex Ante Measure Cost Study	http://www.energydataweb.com/cpucFiles/pdaDocs/1100/2010-2012%20WO017%20Ex%20Ante%20Measure%20Cost%20Study%20-%20Final%20Report.pdf
Bureau of Labor Statistics (BLS)	http://www.bls.gov/oes/current/oes_md.htm#49-0000.

4.2.6 Calculate the Measure-Level Replacement Benefits

Using the algorithm and parameter values summarized above, we calculated the present value of benefits for each measure for each utility program. These results are reported in Table 4-8 without labor costs and in Table 4-9 with labor costs. Of course without labor costs, no benefits are ascribed to occupancy sensors.

Table 4-8: Measure-Level O&M Benefits Without Labor – 5% Discount Rate

Measure Type	Per-Unit $ Benefits Without Labor: PV Unit Costs Over Measure Lifetime – Measure ($)	PV Unit Costs Over Measure Lifetime – Baseline ($)	Net PV Unit Benefits Over Measure Life ($)	Net PV Unit Benefits Over Measure Life (cents/lifetime kWh saved)	Total $ Benefits Without Labor: NTGR	Net # of Units	Net PV of Net Benefits Over Life of 2013 Program Measures ($)
BGE SBDI							
CFL ROB	0.00	12.34	12.34	4.2	0.74	7,368	90,898
LF Fixture ROB	14.83	20.64	5.81	0.1	0.74	44,324	257,509
Exterior LED Lighting ROB	0.00	115.29	115.29	0.8	0.74	4,207	485,032
BGE Prescriptive							
LF Fixture ROB	15.57	29.13	13.56	0.3	0.72	50,074	679,041
LED ROB	0.00	47.95	47.95	2.5	0.72	31,623	1,516,304
Exterior LED Lighting ROB	0.00	155.95	155.95	1.4	0.72	9,426	1,469,904
Occupancy Sensor	0.00	0.00	0.00	0.0	0.72	25,577	0
PEPCO SBDI							
LF Fixture ROB	14.83	20.64	5.81	0.1	0.74	49,033	284,869
LED ROB	0.00	47.95	47.95	2.3	0.74	48,039	2,303,448
Occupancy Sensor	0.00	0.00	0.00	0.0	0.74	7,676	0
PEPCO Prescriptive							
LF Fixture ROB	15.57	29.13	13.56	0.2	0.72	5,424	73,560
LED ROB	0.00	47.95	47.95	1.1	0.72	21,829	1,046,682
Occupancy Sensor	0.00	0.00	0.00	0.0	0.72	3,853	0
DPL SBDI							
LF Fixture ROB	14.83	20.64	5.81	0.1	0.74	3,868	22,472
LED ROB	0.00	47.95	47.95	2.2	0.74	21,925	1,051,309
Occupancy Sensor	0.00	0.00	0.00	0.0	0.74	4,392	0
DPL Prescriptive							
LF Fixture ROB	15.57	29.13	13.56	0.2	0.72	3,344	45,343
LED ROB	0.00	47.95	47.95	1.5	0.72	5,195	249,087
Occupancy Sensor	0.00	0.00	0.00	0.0	0.72	1,089	0
SMECO SBDI							
LF Fixture ROB	14.83	20.64	5.81	0.1	0.74	2,016	11,711
LED ROB	0.00	59.79	59.79	1.0	0.74	865	51,723

SMECO Prescriptive							
LF Fixture ROB	15.57	29.13	13.56	0.5	0.72	6,180	83,812
LED ROB	0.00	47.95	47.95	2.7	0.72	1,167	55,962
Exterior LED Lighting ROB	0.00	155.95	155.95	1.4	0.72	348	54,233
Occupancy Sensor	0.00	0.00	0.00	0.0	0.72	1,053	0
PE Prescriptive							
LF Fixture ROB	15.57	29.13	13.56	0.2	0.72	10,069	136,546
Exterior LED Lighting ROB	0.00	47.95	47.95	1.8	0.72	10,104	484,467
Exterior LED	0.00	155.95	155.95	1.5	0.72	1,440	224,567
Occupancy Sensor	0.00	0.00	0.00	0.0	0.72	2,557	0
Note: The PE SBDI program was not included due to insufficient tracking data detail.							

Table 4-9: Measure-Level O&M Benefits Including Labor – 5% Discount Rate

Measure Type	Per-Unit $ Benefits Including Labor				Total $ Benefits Including Labor		
	PV Unit Costs Over Measure Lifetime		Net PV Unit Benefits Over Measure Life ($)	Net PV Unit Benefits Over Measure Lifetime (cents/lifetime kWh saved)	NTGR	Net # of Units	Net PV of Net Benefits Over Life of 2013 Program Measures ($)
	Measure ($)	Baseline ($)					
BGE SBDI							
CFL ROB	0.00	25.89	25.89	8.8	0.74	7,368	190,730
LF Fixture ROB	19.79	30.87	11.09	0.3	0.74	44,324	491,369
Exterior LED Lighting ROB	0.00	125.85	125.85	0.8	0.74	4,207	529,424
BGE Prescriptive							
LF Fixture ROB	20.78	43.58	22.80	0.4	0.72	50,074	1,141,624
LED ROB	0.00	57.51	57.51	3.0	0.72	31,623	1,818,668
Exterior LED Lighting ROB	0.00	170.22	170.22	1.5	0.72	9,426	1,604,435
Occupancy Sensor	0.00	185.51	185.51	8.1	0.72	25,577	4,744,961
PEPCO SBDI							
LF Fixture ROB	19.79	30.87	11.09	0.3	0.74	49,033	543,576
LED ROB	0.00	57.51	57.51	2.7	0.74	48,039	2,762,776
Occupancy Sensor	0.00	185.51	185.51	10	0.74	7,676	1,424,014

PEPCO Prescriptive							
LF Fixture ROB	20.78	43.58	22.80	0.3	0.72	5,424	123,672
LED ROB	0.00	57.51	57.51	1.3	0.72	21,829	1,255,399
Occupancy Sensor	0.00	185.51	185.51	3.7	0.72	3,853	714,736
DPL SBDI							
LF Fixture ROB	19.79	30.87	11.09	0.3	0.74	3,868	42,880
LED ROB	0.00	57.51	57.51	2.6	0.74	21,925	1,260,949
Occupancy Sensor	0.00	742.06	742.06	6.6	0.74	4,392	814,762
DPL Prescriptive							
LF Fixture ROB	20.78	43.58	22.80	0.3	0.72	3,344	76,232
LED ROB	0.00	57.51	57.51	1.8	0.72	5,195	298,757
Occupancy Sensor	0.00	185.51	185.51	5.3	0.72	1,089	202,092
SMECO SBDI							
LF Fixture ROB	19.79	30.87	11.09	0.3	0.74	2,016	22,346
LED ROB	0.00	71.71	71.71	1.2	0.74	865	62,037
SMECO Prescriptive							
LF Fixture ROB	20.78	43.58	22.80	0.8	0.72	6,180	140,908
LED ROB	0.00	57.51	57.51	3.3	0.72	1,167	67,122
Exterior LED Lighting ROB	0.00	170.22	170.22	1.5	0.72	348	59,197
Occupancy Sensor	0.00	185.51	185.51	6.4	0.72	1,053	195,280
PE Prescriptive							
LF Fixture ROB	20.78	43.58	22.80	0.3	0.72	10,069	229,566
LED ROB	0.00	57.51	57.51	2.1	0.72	10,104	581,074
Exterior LED Lighting ROB	0.00	170.22	170.22	1.7	0.72	1,440	245,120
Occupancy Sensor	0.00	185.51	185.51	3.8	0.72	2,557	474,309
Note: The PE SBDI program was not included due to insufficient tracking data detail.							

4.2.7 Estimate Impact of Lamp Replacement Benefits on Utility Program-Level TRC Benefit Cost Estimates

For each measure, the present value per-unit lamp replacement benefits and per-unit occupancy sensor benefits were multiplied by the number of corresponding units to calculate the present value total lamp replacement benefits. For each utility program, the present value total benefits were then summed.

The present value O&M benefits were then added to the present value electric benefits from the preliminary 2013 EmPOWER cost effectiveness analysis of the 2013 Prescriptive and SBDI programs. All calculations are done separately for lamp replacement benefits with labor and lamp replacement benefits without labor.

4.3 Results and Application

The TRC results for the Prescriptive programs without O&M benefits are shown in Table 4-10 and the results with O&M benefits are shown in Table 4-11.

Table 4-10: 2013 C&I Prescriptive Program Total Resource Cost Effectiveness – Without O&M Benefits

Utility	PV Total Benefits ($)	PV Costs ($)	TRC B/C Ratio
BGE	53,559,467	22,078,288	2.43
DPL	6,954,317	2,194,279	3.17
PE	3,270,063	3,330,411	0.98
Pepco	39,524,703	9,275,614	4.26
SMECO	2,860,625	1,176,407	2.43
Statewide	**106,169,175**	**38,054,999**	**2.79**

Table 4-11: 2013 C&I Prescriptive Program Total Resource Cost Effectiveness – Including O&M Benefits

	Without Labor Costs			With Labor Costs		
Utility	NPV O&M Benefits ($)	PV Total Benefits including O&M ($)	TRC B/C Ratio	NPV O&M Benefits ($)	PV Total Benefits including O&M ($)	TRC B/C Ratio
BGE	3,665,248	57,224,715	2.59	9,309,689	62,869,156	2.85
DPL	294,430	7,248,747	3.30	577,081	7,531,398	3.43
PE	845,581	4,115,644	1.24	1,530,070	4,800,133	1.44
Pepco	1,120,242	40,644,945	4.38	2,093,807	41,618,510	4.49
SMECO	194,008	3,054,633	2.60	462,506	3,323,131	2.82
Statewide	**6,119,508**	**112,288,683**	**2.95**	**13,973,153**	**120,142,328**	**3.16**

The TRC results for the SBDI programs without O&M benefits are shown in Table 4-12 and the results with O&M benefits are shown in Table 4-13.

Table 4-12: 2013 SBDI Program Total Resource Cost Effectiveness – Without O&M Benefits

Utility	PV Total Benefits ($)	PV Costs ($)	TRC B/C Ratio
BGE	22,923,537	13,939,265	1.64
DPL	13,017,430	7,414,614	1.76
PE	295,010	1,010,961	0.29
Pepco	71,257,078	23,303,199	3.06
SMECO	917,011	814,595	1.13
Statewide	**108,410,067**	**46,482,634**	**2.33**

Table 4-13: 2013 SBDI Program Total Resource Cost Effectiveness – Including O&M Benefits

	Without Labor Costs			With Labor Costs		
Utility	NPV O&M Benefits ($)	PV Total Benefits including O&M ($)	TRC B/C Ratio	NPV O&M Benefits ($)	PV Total Benefits including O&M ($)	TRC B/C Ratio
BGE	833,439	23,756,976	1.70	1,211,523	24,135,060	1.73
DPL	1,073,781	14,091,211	1.90	2,118,591	15,136,021	2.04
PE*	NA	295,010	0.29	NA	295,010	0.29
Pepco	2,588,317	73,845,395	3.17	4,730,366	75,987,444	3.26
SMECO	63,434	980,445	1.20	84,384	1,001,395	1.23
Statewide	**4,558,970**	**112,969,037**	**2.43**	**8,144,863**	**116,554,930**	**2.51**

*The PE SBDI program was not included due to insufficient tracking data detail.

Table 4-13 presents the ratios of TRC Benefit Cost Ratios with O&M benefits to TRC Benefit Cost Ratios without O&M benefits for each utility's Prescriptive and SBDI program including labor. Statewide, if lamp replacement and occupancy sensor benefits were included, the TRC benefits would increase by 13 percent for Prescriptive programs and 8 percent for the SBDI programs. PE's Prescriptive program would receive the greatest percentage boost, with its TRC increasing by nearly one-half.

Table 4-14: Ratio of TRC with O&M Benefits to TRC without O&M Benefits

Utility	Prescriptive	SBDI
BGE	1.17	1.05
DPL	1.08	1.16
PE	1.47	NA
PEPCO	1.05	1.07
SMECO	1.16	1.09
Statewide	1.13	1.08

For the Cost Effectiveness Working Group for the EmPOWER Potential Study, we recommend that the O&M benefits including labor costs be used in all of the cases. Starting with the PY2014 ex post cost effectiveness analysis, we recommend these benefits including labor costs be included in the TRC test, as well as the participant test and societal test if those tests are included in the ex post analyses.

We can provide either or both annual benefits or lifetime present value benefits upon request. The values should be multiplied by the number of measure units that were induced by the program – the number of units should be adjusted to reflect free riders. If annual values are used, a price inflation escalator should be applied. Undiscounted annual benefits are provided in Chapter 6.

These are participant O&M benefits from installing more efficient lamps and fixtures in commercial and industrial sites are analogous to the O&M benefits that have been included in the ex post cost effectiveness analyses of the residential lighting programs since 2011. Calculation of these benefits is reasonably straight forward and all assumptions are provided and can easily be amended if the Cost Effectiveness Working Group or the Commission thinks it is appropriate. If these O&M benefits are determined to not be appropriate to include in the TRC test, then we recommend that the benefits currently included and quantified for residential incandescent replacements be excluded as well.

5

Arrearage

5.1 Introduction

Utilities across the country find high levels of arrearage[1] time-consuming and expensive. Arrearages cost utilities money as they are essentially loaning money to their customers until arrearages are paid off. While a portion of arrearages can be recovered in late payment charges, these charges also often remain unpaid. Energy efficiency programs resulting in higher rates of on-time customer bill payment offer utilities additional benefits beyond the value of energy and demand savings. Utilities can reduce arrearage levels by offering programs—particularly for low income customers—that reduce customers' energy bills[2], thus making it easier for them to their pay bills on time.

Arrearage savings have been documented extensively over the past 20 years by utilities across the country. The savings associated with arrearage reductions are commonly cited as "non-energy benefits." Previous arrearage studies are often combined with qualitative or quantitative survey efforts in order to understand what the customer valued about the program and what led to their increased ability to pay their utility bill.[3]

The following is a list of bill payment-related benefits identified in the literature:

1. Carrying costs on arrearages (utility)
2. Reduced bad debt write-offs (utility)
3. Reduced costs for bill collection process (utility)
4. Reduced levels of disconnects / connects (shut-offs) (utility)
5. Reductions in low income subsidies and payments (utility)
6. Increased ability to pay utility bill (participant)
7. Increased levels of disposable income (participant)
8. Improvements to income equity (societal benefit)

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1 Arrearage is the amount of unpaid bills accruing to a utility customer.

2 Electric and Gas savings are included in these saving estimates

3 Note: There are NEBs associated with reduced arrearage for customers other than low income; however, the savings to the utility are not as high. Consequently, this is not an area that utilities have spent much time researching.

While this list suggests there are a large number of non-energy payment-related benefits accruing to customers and society, in this chapter, our examination will focus solely on the quantification of "utility" arrearage reduction benefits (#1 on list above – carrying costs on arrearages) that accrue directly to the utility from a larger number of customers paying their bills on time. Arrearage reductions due to "low income" customer program participation have been shown repeatedly to exist in numerous studies across the country. Relatively few studies have been completed that quantify the arrearage benefits from programs delivered to the general population. If this information is desired, we would recommend that these benefits to the general population be quantified through Maryland specific research.

Our recommendation is for the Maryland utilities to either use a documented two percent savings estimate (details of how this two percent was derived are detailed section 5.2 below), or to conduct utility-specific studies on payment-related benefits, specifically arrearage studies for Maryland low income programs. These primary research efforts would provide a detailed understanding of differences in bill payment rates between participants and non-participants in these programs and show how these translate into reductions in financial costs for Maryland utilities. In addition some of the other non-energy benefits from low income programs listed above could be investigated. However, while not specific to Maryland, there appears to be enough research conducted nationwide in the past ten years to justify using secondary research to quantify arrearage benefits for low income programs in Maryland. While the savings per customer are small, leaving these benefits on the table and out of the TRC test underestimates the total value of the energy efficiency investments made by customers to society and the direct financial benefits to the utility.

A recent ACEEE report[4] that surveyed state policies does not go into detail on which utility non-energy benefits are included in cost-effectiveness tests, and a recent Synapse Energy Economics study[5] of state policies in eight eastern states includes arrearages as part of a larger "utility other program impacts" category, which includes arrearages as well as other utility perspective benefits.

Arrearage benefits accruing to the utility should be applied to the TRC test because these reductions in costs are real savings to utility program administrators and, as such, should be included with other utility cost impacts. The recommended values we suggest are in terms of the carrying cost to the utility of holding short term debt due to customer arrearages. Studies across the country show proven arrearage reduction from energy efficiency measures in limited income households. Arrearage reductions resulting from energy efficiency measures in non-limited

4 Kushler, Martin, Seth Nowak, and Patti White. A National Survey of State Policies and Practices for the Evaluation of Rate-Payer Funded Energy Efficiency Programs. ACEEE Report U122. February 2012.

5 Wolf, Tim, Erin Malone, Jenn Kallay, and Kenji Takahashi. *Energy Efficiency Cost Effectiveness Screening in Northeast and Mid-Atlantic States*. Synapse Energy Economics Inc. October 2013.

income programs are also sometimes cited, but the reductions are significantly lower and likely not worth quantifying. We recommend that arrearage benefits only be applied to the energy savings from the Maryland limited income program.[6]

5.2 Literature Review

Our team reviewed ten arrearage reports completed over the past 10 years. For this analysis, our team focused on the four studies (described below) that we feel are the most relevant to Maryland based on their comprehensiveness and recent dates of completion.

5.2.1 SERA Inc. Research

The first two studies are a compilation and analysis of dozens of reports analyzed by Skumatz Economic Research Associates, Inc. (SERA) for the California Public Utilities Commission (CPUC) and the NRDC (for Maryland).

In 2010, SERA authored a report[7] for California where the CPUC required that utility program managers account for utility and participant low income benefits such as reduced shutoffs and calls to the utility, lower levels of relocation, and perceived benefits in comfort. The report documents the results from numerous studies on arrearage reductions and indicates a wide range of values for reduced arrearage. Most program participants report the value of benefits caused by the program is in the range of 20-30 percent of dollar value of the annual energy savings. The reduction in arrearage caused by efficiency investments was estimated at 20-25 percent of the total arrearage value. The dollar values in annual carrying cost reduction range from $2–$32 per participant. Evaluations of the arrearage effect of low income programs report significantly higher arrearage cost savings, especially if participants with arrearages are targeted.

The findings in Table 5-1 are based on 15 low-income payment studies across the country. In 2014, SERA produced a report specifically for Maryland[8] that recommends an arrearage reduction benefit of two percent of retail bill savings, or roughly $2.50 - $4.00 per participant. This estimate is based on the results of SERA's 2010 California study (Table 5-2), which was a compilation of non-energy benefit studies across the country. The report recommends a higher arrearage reduction benefit of up to 16 percent of retail bill savings ($13 per participant) if low-income subsidies are avoided.

6 Arrearage reductions are found to be the greatest in programs that specifically target high arrearage customers; Maryland programs however do not specifically target high arrearage customers.

7 Skumatz, Lisa. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low-Income Program Analysis in California. SERA Inc. May 2010.

8 Skumatz, Lisa. Non-Energy Impacts / Non-Energy Impacts and Their Role and Values in Cost Effectiveness Tests, State Of Maryland. SERA Inc. March 2014.

Table 5-1: Weatherization Non-Energy Benefit Value Ranges – SERA 2014

NEB Estimates from Multiple Weatherization Studies: Dollar and Percentage Analysis	Dollar NEB Values Range Low-High		Typical Value	Percent NEB Values Range Low-High		Typical Value	Notes
UTILITY PERSPECTIVE							
Payment-related							
Carrying cost on arrearages	$1.50 -	$4.00	$2.50	0.6% -	4.4%	2.0%	Total arrearages $2-$100; $20-30 typical
Bad Debt Write-offs	$0.50 -	$3.75	$1.75	0.4% -	2.0%	0.7%	
Reduced LI subsidy pymt/discounts	$3.00 -	$25.00	$13.00	3.9% -	29.0%	16.4%	IF low income program
Shutoffs / Reconnects	$0.10 -	$3.65	$0.65	0.1% -	4.4%	0.5%	
Notices	$0.05 -	$1.50	$0.60	0.1% -	1.8%	0.9%	
Customer calls / collections	$0.40 -	$1.60	$0.90	0.2% -	1.9%	0.6%	
Service Related							
Emergency / safety	$0.10 -	$8.50	$3.25	0.1% -	2.7%	0.8%	Few good studies
Other Primary Utility							
Insurance savings	$0.00 -	$0.00	$0.00	1.2% -	1.2%	1.2%	Few studies
T&D savings (usually distrib)	$0.13 -	$2.60	$1.40	0.9% -	2.1%	1.2%	Straightforward, but few studies
Fewer substations / infra	$0.00 -	$0.00	$0.00	0.0% -	0.0%	0.0%	Impt / needs more studies
Power quality / reliability	$0.00 -	$0.00	$0.00	0.0% -	0.0%	0.0%	Important; value of service study approach
Other Primary Utility	$0.00 -	$0.00	$0.00	0.0% -	0.0%	0.0%	
TOTAL UTILITY NEBs	$5.78 -	$50.60	$24.05	7.4% -	49.5%	24.4%	
UTILITY NEBs MULTIPLIER	3% -	25%	12%	0.4% -	14.8%	3.3%	

Source: Table 3.4: Non-Energy Impacts / Non-Energy Impacts and Their Role and Values in Cost Effectiveness Tests, State Of Maryland, SERA Inc., March 2014, p. 28.

Table 5-2: Results from Low-Income Payment Studies in California Report – SERA 2010

ID Perspective or NEB Category	Summary of Values (per participant / yr.); Implications
UTILITY PERSPECTIVE	
Carrying Cost on Arrearages	Estimates of arrearage for programs targeted at general low income population range from 20-30% of annual bill savings. Dollar values range from $2/participant, to $32/part; (several in range of $60). Estimated arrearage savings are higher for programs targeting high arrearage customers
Bad Debt Written Off	Impact values usually in the 20-35% range; not many studies specifically on this feature. Values $60+ for those affected, $2 when averages across all participants.
Shutoffs	Values on order of $2 or less for many utilities; several found very high values ($100+)
Reconnects	Net values from pennies to $50+ reconnect charge (many did not multiply times incidence)
Notices	Few study these separately
Customer Calls / Bill or Emergency-Related	Values on order of $0.50.
Other Bill Collection Cost	Few study these separately.
Emergency Gas Service Calls (for gas flex connector and other programs)	Based on 2 main studies – Magouirk and Blasnik.
Insurance Savings	Very rarely examined
Transmission and Distribution Savings (usually distribution)	Not often separately studied; embedded in utility avoided costs for some. Rules of thumb estimated percentages for some.
Fewer Substations, etc.	Not studied to date
Power Quality / Reliability	Not studied to date
Reduced Subsidy Payments (low income)	Very directly related to the energy savings and utility's discount rate
Other	Not available
Total Perspective Utility	**Lowest of the 3 perspectives. Totals range from $4-$31/HH.**

Source: Table 4.1: Values for NEBs for Low Income Programs for Utilities around the Country. Non-Energy Benefits Report, SERA Inc., May 2010, p. 25.

5.2.2 Massachusetts Study

A study for Massachusetts program administrators[9] conducted by Tetra Tech and Nexus Market Research in 2011 indicates that the value of reduced carrying cost on arrearages ranges from $1.37 - $4.00 per participant, depending on the population targeted and method of analysis used. Table 5-3 shows results from low-income weatherization programs. The study indicates that comparison of arrearage saving estimates across multiple evaluations of low income programs is difficult for at least two reasons. First, these studies do not consistently report differences in the energy and dollar savings achieved by participants who are likely to lead to different levels of reduction in the absolute dollar amount of delinquent bills owed to utilities. Second, it is likely that carrying charges or interest rates applied to this debt load are different across utilities.

Table 5-3: Results of Low-Income Arrearage Studies in Massachusetts Report

Study	Reported NEI Value, $/year/participant					
	Carrying Cost on Arrearages	Bad Debt Write-Offs	Terminations and Reconnections	Customer Calls	Notices	Safety-Related Emergency Calls
WI Low-income Weatherization (Skumatz and Gardner, 2005)	1.37	--	0.13	0.43	0.30	--
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	--	6.09	0.55	--	--	6.91
MA Low-income Weatherization (Skumatz Economic Research) Associates, 2002)	1.71	3.62	--	0.59	--	0.40
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	2.03	2.24	0.10	0.55	1.16	0.21
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	3.76	0.48	0.07	1.58	1.49	0.07
VT Low-income Weatherization (Riggert et al., 1999)	--	--	7.00	--	--	15.58
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	2.09	2.34	0.33	0.07	0.04	7.91
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	4.00	4.50	0.63	0.13	0.08	15.00

Source: Table 4-2: Reported NEI Values (Dollars per Participant per Year) from Recent NEI Studies of Low-Income Programs. Massachusetts NEI Evaluation, August 2011

5.3 Methods Assessment

The studies we reviewed use a pre-post treatment/comparison group method to estimate average arrearage reductions across low income programs. Typically this means that one year of billing data pre-treatment and one year of billing data post-treatment is analyzed and the difference in

9 Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation. Tetra Tech and Nexus Market Research. August 2011.

total arrearage reduction for the utility is calculated for a random sample of low-income program participants. This arrearage reduction is then compared to arrearage levels for a random sample of low-income utility customers who did not receive energy efficiency treatments to account for economic conditions, weather, and other external conditions that may affect ability to pay. Any arrearage reduction in the sample of non-treated customers is then subtracted from arrearage reduction in the sample of low-income customers who did receive energy efficiency treatments to get the net effect of the treatment on arrearage reduction. This method results in an unbiased estimate of arrearage reduction when a robust sample of utility customer bills is studied. If desired, Maryland utilities could consider conducting their own arrearage reduction studies with a similar methodology for either low income programs or perhaps using the same methodology to estimate potential arrearage impacts at the portfolio level.

Until such studies are completed, Itron agrees with the SERA NRDC arrearage recommendation for Maryland which (based on the comprehensive SERA/Cadmus California report estimated as the average reduction in carrying cost from the results of 15 arrearage studies). Our research found that the most comprehensive review of arrearage studies is contained in the California Low-Income study by SERA[10] (shown in Table 5-2).

5.4 Credibility of Sources

The results reported in the two SERA studies are credible for use in Maryland due to the extensive secondary research contained in them. These studies contain the largest review of arrearage reduction study results in terms of utility carrying cost reduction. The two percent of bill savings recommendation ($2.50 - $4.00) from the SERA study is consistent with the arrearage benefit recommendation in the Massachusetts study[11] of $0.50 - $7.50 per low-income participant.

The studies meet several important criteria and standards:

- They describe a plausible hypothesis for what causes arrearage reductions.
- They entertain the possibility that there may be costs, rather than benefits, related to the installation of energy efficiency measures.
- Estimates of arrearage reductions report fairly consistent values from the 1990's to those studies completed in the early 2000's.
- Interest rates and the fraction of customers who qualify for low income status have been fairly consistent over the last decades.

10 Non-Energy Benefits Report, SERA Inc., May 2010.
11 Massachusetts NEI Evaluation, August 2011.

- Estimates were conducted by experienced third party consultants who are not advocates or affiliated with any advocacy groups.
- The studies were reviewed by utility clients and their stakeholders before final publication.

5.5 Key Assumptions

5.5.1 Maryland Limited Income Customers Have Similar Payment Patterns to Customers in Other States

Using the average arrearage reduction values found for low-income program participants in other states means that we believe that Maryland low-income participants would behave in a similar manner as participants in other states with the extra money available due to energy bill savings. We believe this is a reasonable assumption since the value is based on a large number (15) of arrearage studies where the characteristics of the low income populations and building stock studied are similar to the conditions in Maryland.

5.5.2 The Amount of Arrearage Reduction Cost is Linearly Related to Bill Savings

The amount of bill savings achieved by programs depends on the mix of measures in low-income programs. This mix is dependent both on participant investment and utility funding as well as differences in climate and baseline conditions. It is possible that very high bill savings in some states will result in greater arrearage reductions, or very low bill savings per customer will result in significantly lower arrearage reductions. We do not currently have a method to investigate this issue with the absence of a Maryland-specific arrearage study.

5.6 Concerns and Uncertainties

The following sections discuss some of the concerns expressed by the Maryland utilities and stakeholders during an initial review of arrearage benefits. The Itron team researched these issues. Our analysis and recommendations are included below.

5.6.1 Interaction with Late Payment Charges

Issue raised: Is it possible that estimating benefit values for arrearage reductions may be unnecessary because some or all of the cost to the utility is made up by late payment charges to customers?

Response: The benefits of reducing arrearage costs are both a benefit to participants and to the utility regardless of whether utilities can recover some of the revenue lost through late payment charges. The utility, customer and society are all better off in a market where customer bills get paid on time, levying late charges simply increases the transactions costs to all involved and in most cases will result in a bill increase for everyone because late charges do not cover all of the carrying costs for bad debt.

While at first glance, there appears to be merit in this question, almost all utilities levy late payment charges on customers and yet arrearage studies still find utility benefits in arrearage reductions from energy efficiency measures. In addition, even though the utility may levy a late payment charge, this amount will also likely remain unpaid and is just added to the total level of customer arrearage (or carrying costs on unpaid bills due).

We would argue that even if these late charges potentially make up for the loss in utility revenue due to increased carrying costs, both charges are a net loss to society and likely to result in higher rates for all ratepayers. Thus the primary focus should be on reducing the proportion of customers who pay their bill late, regardless of whether the utility can recoup these arrearage costs in base rates or late payment changes later. If the Maryland stakeholders feel that this is still an issue, our suggestion is that the "late payment charge" topic should be examined within the a new study gathering data on arrearage costs across the Maryland population segments of interest.

5.6.2 Interaction with Other Low-Income Payment Assistance Programs

Issue Raised: Maryland utilities and non-profits have several forms of low-income payment assistance programs available to low income households in addition to the utility or DHCD offered low income energy efficiency programs. Savings from the energy efficiency programs may affect eligibility for participation in other assistance programs and have a feedback or interactive effect on the likelihood that energy bills from participants will be paid on time.

Response: While we recognize that these interactive effects may affect the estimate of the average arrearage cost savings due solely to utility energy efficiency programs, we are confident that several other states also offer multiple programs available to local low income populations and the potential interactive effect from these other programs did not have any material effect on the estimated arrearage reductions per customers. This interactive effect can be controlled for as long as the sample design is designed to ensure the treatment group only contains participants in low income programs who are not simultaneously participating in other programs. In either event, our recommendation would be for utilities, if desired, to quantify the benefit for either their programs only or for all assistance programs through primary research.[12]

[12] Research shows arrearage benefits from 2 percent to 16 percent (or $13 per participant depending on the level of payment assistance avoided. Skumatz, Lisa. *Non-Energy Impacts / Non-Energy Impacts and Their Role and Values in Cost Effectiveness Tests, State Of Maryland*. SERA Inc. March 2014

5.7 Recommended Values

Our recommendation for Maryland is that a conservative estimate in the lower end of the range of published estimates - equivalent to two percent of bill savings - be used to value arrearage reductions. By conservative, we mean the recommended value is within the lowest quartile or 25 percent of estimates found in the literature. The expected value or mean estimate would be closer to 4 percent of bill savings but given the uncertainties in transferring this value across states, we recommend the conservative value.

The latest verified impact evaluation for the EmPOWER limited income programs was for the 2011 program year. The 2011 EmPOWER Limited Income evaluation documented average participant savings of 1,945 kWh per year which result in an average of $253 of bill savings per year, as shown in Table 5-4. Applying a 5% real discount rate over the weighted average life of the 2011 limited income programs, the lifetime arrearage financing benefit was $55 per participant.

Table 5-4: Arrearage Reduction Recommendation for Maryland

	Annual kWh Savings per Program Participant[13]	Annual Retail Bill Savings per Participant[14]	Lifetime Present Value Arrearage Carrying Cost per Participant[15]
Arrearage Reduction Recommendation	1,945	$253	$55

5.8 Impact on Program Cost Effectiveness

We recommend that this $55 benefit be added to the present value benefits when calculating the Limited Income program TRC benefit/cost ratio. Alternatively, a benefit equal to 2% of each kWh saved over the life of the measures could be applied. Incorporating the arrearage financing cost benefit into the cost effectiveness analysis of limited income programs would increase the statewide program TRC by roughly 1.5%. The statewide TRC benefit/cost ratio for the programs was 0.446. If the arrearage financing cost benefit had been included, the TRC benefit/cost ratio would have been 0.453. If the arrearage financing cost benefit was also applied to gas utility bill savings, the TRC benefit/cost would increase by nearly 2% since most of the non-electric benefits counted in the 2011 analysis was from gas savings.

13 Navigant Consulting, Empower Maryland 2011 Evaluation Report, Chapter 8: Limited Income Programs, March 8, 2012, pp.7-8.

14 Based on May 2013 average statewide residential electric rate of 13 cents per kWh from US Energy Information Administration, Electric Power Monthly, July 28, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a

15 Based on 2% of electric bill savings using a 5% real discount rate.

Savings due to carrying cost reductions are small and have remained fairly stable and somewhat consistent over time and location. However, if desired, Maryland utilities can conduct a study of utility arrearage reductions attributable to low income program participants if a more accurate estimate of non-energy benefits associated with measures installed in low income households is desired. Previous primary research has tended to use a pre/post treatment/comparison methodology to quantify these reduced arrearage benefits and benefits to the low income participants themselves. Given that Itron is recommending that a similar pre/post research design be used to verify the energy saving from the low income program in 2014, the incremental cost of completing this NEB analysis could be quite low.

Interviews with program participants could be used to research the savings attributable to low-income subsidy payment reductions available from other programs and also to obtain an understanding of the value that participants obtain through program participation and the factors that enabled them to pay their bills more promptly. However it is important to note that the relatively small benefit of two percent for arrearages alone suggests that a larger scope that might examine all or most of the non-energy benefits associated with these programs might be more cost efficient for the utilities.

We estimate the incremental cost of estimating the potential effect of low income programs on utility arrearages in Maryland to be roughly $10,000 assuming a sample size of 100 participants and 100 controls. This is the cost to the evaluation team. We do not have any knowledge of how difficult or easy it would be for the host utility to match late payment records with sample participants and provide the interest rate used to accrue carrying charges on late bills. We suggest this topic be discussed during the next available working group meeting of the low income group to assess the level of interest in this topic.

6

Summary of Recommendations

Four non-energy benefits were estimated as part of this analysis: air emissions, comfort, commercial operations and maintenance (O&M), and utility bill arrearages. In all four cases, we provide a recommended value and methods for including them in future ex ante and ex post EMPOWER costs effectiveness analyses.

This is not a comprehensive estimate of all potential non-energy benefits associated with the EmPOWER programs, nor even of the four individual benefits categories. Many types of benefits were not covered in this analysis. However, including these benefits would greatly improve the accuracy of future EmPOWER cost effectiveness analyses and better align those analyses with EmPOWER policy objectives.

Below, we summarize the recommended values and methods for applying them in EmPOWER cost effectiveness analyses.

Table 6-1 Summary of Recommended Values and Application

Benefit	Case	Programs	Value	Basis	B/C Test
Air Emissions	Medium Case (Recommended)	All	1.1 cents	Should be multiplied by all kWh saved for the life of each measure and then multiplied by the NTG ratio for each measure. Values are in 2014 dollars; a price inflation escalator should be applied.	TRC, SCT
	High Case		2.2 cents		
	Low Case		0.2 cents		
Comfort	Medium Case (Recommended)	HPwES and Low Income	HPwES: $136 Low Income: $110	Values should be multiplied by the number of comprehensive air sealing participants for each year of the measure life and then multiplied by 1 minus the free ridership rate. Values are in 2014 dollars; a price inflation escalator should be applied.	PCT, TRC, SCT
	High Case		HPwES: $204 Low Income: $165		
	Low Case		HPwES: $34 Low Income: $27		
C&I O&M	Medium Case (Recommended)	C&I Prescriptive and SBDI	Varies by measure (see Table 6-2)	Should be multiplied by the number of measure units that were induced by the program and then multiplied by 1 minus the free ridership rate. Annual and/or discounted lifetime benefits are available upon request. Values are in 2014 dollars; if annual values are used, a price inflation escalator should be applied.	PCT, TRC, SCT
	High Case				
	Low Case				
Arrearages	Medium Case (Recommended)	Limited Income	2% of kWh savings.	Should be applied to all kWh saved over the life of the measures installed as part of the program and then multiplied by 1 minus the free ridership rate.	PAC (UCT), TRC, SCT
	High Case				
	Low Case				

Table 6-2 C&I Prescriptive and SBDI Program O&M Benefits

Utility Program	Measure Type	O&M Net Benefits Per Measure Unit (2014 $)														
		Year														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
BGE SBDI	SBDI CFL ROB	7.73	7.73	7.73	5.88	-	-	-	-	-	-	-	-	-	-	-
BGE SBDI	SBDI Linear Fluorescent Fixture ROB	-	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-
BGE SBDI	SBDI Exterior LED ROB	-	-	30.56	-	30.56	-	30.56	-	30.56	-	30.56	-	30.56	-	-
BGE Prescriptive	Prescriptive Linear Fluorescent Fixture ROB	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-	23.20
BGE Prescriptive	Prescriptive Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
BGE Prescriptive	Prescriptive Exterior LED ROB	-	30.56	-	30.56	30.56	-	30.56	-	30.56	30.56	-	30.56	30.56	-	-
BGE Prescriptive	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
PEPCO SBDI	SBDI Linear Fluorescent Fixture ROB	-	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-

PEPCO SBDI	SBDI Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
PEPCO SBDI	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
PEPCO Prescriptive	Prescriptive Linear Fluorescent Fixture ROB	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-	23.20
PEPCO Prescriptive	Prescriptive Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
PEPCO Prescriptive	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
DPL SBDI	SBDI Linear Fluorescent Fixture ROB	-	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-
DPL SBDI	SBDI Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
DPL SBDI	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
DPL Prescriptive	Prescriptive Linear Fluorescent Fixture ROB	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-	23.20
DPL Prescriptive	Prescriptive Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
DPL Prescriptive	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
SMECO SBDI	SBDI Linear Fluorescent Fixture ROB	-	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-

SMECO SBDI	SBDI Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-
SMECO Prescriptive	Prescriptive Linear Fluorescent Fixture ROB	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-	23.20
SMECO Prescriptive	Prescriptive Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
SMECO Prescriptive	Prescriptive Exterior LED ROB	-	30.56	-	30.56	30.56	-	30.56	-	30.56	30.56	-	30.56	30.56	-	-
SMECO Prescriptive	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-
PE Prescriptive	Prescriptive Linear Fluorescent Fixture ROB	-	-	-	-	23.20	-	-	(30.70)	-	23.20	-	-	-	-	23.20
PE Prescriptive	Prescriptive Interior LED ROB	-	12.44	12.44	-	12.44	12.44	-	12.44	12.44	-	-	-	-	-	-
PE Prescriptive	Prescriptive Exterior LED ROB	-	30.56	-	30.56	30.56	-	30.56	-	30.56	30.56	-	30.56	30.56	-	-
PE Prescriptive	Occupancy Sensor	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	24.03	-	-	-	-	-