



Residential Grid Interactive Building Retrofit

A Benefit-Cost Analysis Case Study Applying the National
Standard Practice Manual™

June 2022 – Updated 2025

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1. Introduction and Overview of Case Study

The purpose of this report is to illustrate a benefit-cost analysis (BCA) for a specific distributed energy resource (DER) technology and a use case that is of growing interest in the electric industry: residential grid-interactive efficient building (GEB) retrofit.

GEBs are at the forefront of efforts to leverage buildings as a flexible resource. Today, the country's 129 million buildings consume 40% of U.S. energy and 75% of its electricity, and contribute 35% of annual U.S. carbon emissions.¹ A recent DOE study estimated that by 2030, GEBs could save up to \$18 billion in power system costs and 80 million tons of carbon emissions annually.² The U.S. Department of Energy's (DOE) Building Technologies Office (BTO) is advancing the development of a GEB vision, with a goal to triple EE and demand flexibility in residential and commercial buildings by 2030. Furthermore, federal support for GEBs is expanding, as illustrated by recently funded DOE Connected Communities pilot projects, which aim to demonstrate how energy-efficient and grid-interactive technologies can transform homes and workplaces into connected communities.³

What is a Grid-interactive efficient building (GEB)? An energy-efficient building that uses smart technologies and on-site DERs to provide demand flexibility while co-optimizing for energy cost, grid services, and occupant needs and preferences in a continuous and integrated way.

Source: Neukomm, M., Nubbe, V., & Fares, R. (2019). *Grid-interactive Efficient Buildings: Overview*. U.S. Department of Energy. <https://www1.eere.energy.gov/buildings/pdfs/75470.pdf>

As these new programs/offerings have emerged, challenges with analyzing their benefits and costs have also surfaced. Common challenges that this case study aims to address include accounting for the interactive effects of multiple on-site DERs deployed in a GEB (i.e., EE, DR, and building electrification measures), and making informed assumptions about societal impacts such as GHG emissions and public health, via air quality impacts.

This case study is informed by a real-world BCA and data for a similar use case but has been generalized into an illustrative and hypothetical example for broader applicability. It was developed to demonstrate key factors and challenges with conducting BCA for a combined weatherization (e.g., energy efficiency (EE)), demand response, and building electrification program. In addition, this case study illustrates key BCA considerations for a multi-DER use

¹ Source: <https://www.energy.gov/eere/buildings/articles/meet-does-newest-connected-communities-grid-interactive-efficient-buildings>

² The report finds that over the next two decades, GEBs could deliver between \$100 billion and \$200 billion in savings to the U.S. power system. Satchwell, A., Piette, M., Khandekar, A., Granderson, J., Frick, N., Hledik, R., Faruqui, A., Lam, L., Ross, S., Cohen, J., Wang, K., Urigwe, D., Delurey, D., Neukomm, M., & Nemtzw, D. (2021). *A National Roadmap for Grid-Interactive Efficient Buildings*. United States. <https://gebroadmap.lbl.gov/A%20National%20Roadmap%20for%20GEBs%20-%20Final.pdf>, and <https://www.energy.gov/articles/doe-invests-61-million-smart-buildings-accelerate-renewable-energy-adoption-and-grid>

³ For additional information, see: <https://www.energy.gov/articles/doe-invests-61-million-smart-buildings-accelerate-renewable-energy-adoption-and-grid> and <https://www.energy.gov/eere/buildings/articles/meet-does-newest-connected-communities-grid-interactive-efficient-buildings>

case and demonstrates a specific approach to account for impacts when certain data may be unavailable.⁴

The case study that applies guidance from the [*National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*](#) (NSPM).⁵

2. National Standard Practice Manual

The [*National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources \(2020\)*](#) (“NSPM for DERs” or “NSPM”) provides a comprehensive framework for the cost-effectiveness assessment of DERs.⁶ The manual offers a set of policy-neutral, non-biased, and economically sound principles, concepts, and methodologies to support single and multi-DER benefit-cost analysis. It is intended for use by jurisdictions to help inform which resources to acquire to meet their specific policy goals and objectives using a primary cost-effectiveness test, and it also provides guidance on the use of secondary tests.

The [*Methods, Tools, and Resources Handbook for Quantifying DER Impacts for Benefit-Cost Analysis \(2022\)*](#) (“MTR Handbook”) is a companion document to the NSPM. It provides technical information on how benefits and costs of DER investments can be quantified (monetized or otherwise), with links to resources and tools.

This case study aligns with the fundamental NSPM BCA principles summarized in Table 1, which are referenced where applicable throughout this case study.

⁴ This report addresses some but not all key factors that may affect impacts of different DER types. More information is available in Chapters 6-10 of the [NSPM for DERs](#) on specific DER types and Chapter 11 on multiple on-site DERs.

⁵ National Energy Screening Project (NESP). (2020). National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. . See: [NSPM for DERs](#)

⁶ [*National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*](#), National Energy Screening Project (NESP), (2022).

Table 1: NSPM BCA Principles

Principle 1	Treat DERs as a Utility System Resource DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	Align with Policy Goals Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	Ensure Symmetry Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	Account for Relevant, Material Impacts Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	Conduct Forward-Looking, Long-term, Incremental Analyses Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	Avoid Double Counting Impacts Cost-effectiveness analyses present a risk of double counting of benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double counting.
Principle 7	Ensure Transparency Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	Conduct BCAs Separately from Rate Impact Analyses Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses. Cost-effectiveness analyses should therefore be conducted separately from rate impact analyses.

Key NSPM principles applied to this case study include:

- Ensuring symmetry between the treatment of benefits and costs for each impact in the JSTs (Principle 3);
- Accounting for all relevant impacts, even if difficult to quantify (Principle 4);
- Conducting a forward-looking, incremental analysis over the life of the DER(s) and ensuring no sunk costs are included (Principle 5); and
- Avoiding any double counting of impacts (Principle 6).

Consistent with NSPM Principle 7 – to provide transparency in BCA practice – this case study describes the basis for the primary cost-effectiveness test used, presents the full range of relevant BCA input assumptions and results, and provides information on methodologies used to monetize the impacts. References are made in some cases to the MTR Handbook where

additional information can be found on methods for monetizing impacts, including those that are hard to quantify.

Finally, this case study does not address bill and rate impacts. While it is important for decision-makers to understand how revenue collections will be impacted and how customer rates and energy burdens may change due to DER investments, conducting rate and bill impact analyses should be separate from BCA, consistent with NSPM Principle 8.

BCA Impacts

The key impact categories for BCAs are generally electric utility or gas utility system impacts and non-utility system impacts (i.e., other fuel impacts, host customer impacts, and societal impacts). The range of impacts within each category, and associated definitions, are provided in the Appendix.

This case study addresses the full range of electric utility system impacts. The extent to which non-utility system impacts apply is dependent on the applicable policy goals of the hypothetical jurisdiction. As such, this case study presents a jurisdiction-specific test (JST). A JST may or may not align with traditional cost-effectiveness tests (e.g., Utility Cost Test/Program Administrator Cost Test, Total Resource Cost Test, or Societal Cost Test).⁷

3. Case Study Context and Assumptions

This case study describes the cost-effectiveness analysis of a hypothetical GEB retrofit program that includes ceiling insulation upgrades and air sealing, an air source heat pump (ASHP) to replace a natural gas furnace and central air conditioning (AC), and a smart thermostat that is automatically enrolled in a demand response (DR) program. The program is assumed to be provided by a municipal utility in the Mid-Atlantic. The objective of the BCA is to help determine if the quantified benefits of the proposed program outweigh the proposed costs, using a JST described below.

Reference Case	Residential customers with a 2,500 square foot single family home with: SEER 10 central AC, 80% Annualized Fuel Utilization Efficiency (AFUE) gas furnace, and no DR program participation.
DER Case	Residential customers would retrofit and install combined EE, DR, and building electrification technologies: • EE: Upgrading ceiling insulation & reducing air leakage • Building electrification: Installing an ASHP to replace the natural gas furnace and central AC • DR: installing a smart thermostat with automatic enrollment in a DR program

⁷ See [NSPM for DERs](#) Chapter 3 for additional discussion of traditional cost-effectiveness tests.

3.1 Utility & Grid Profile, Policy Context, and Regulatory Perspective

The municipal utility planning to offer the GEB retrofit program is located in the Mid-Atlantic and is connected to the PJM Interconnection (PJM) RTO. The hypothetical generation mix and resulting emissions are reflective of representative marginal generators for the Mid-Atlantic region, including a significant presence of coal-fired power plants for baseload and marginal natural gas peaker plants.⁸ Relative to other areas of the country, the region is assumed to have moderate avoided energy and capacity costs, which decline in the near term. It is assumed that the jurisdiction's grid profile and generation mix will evolve over time to include more renewable energy resources, as discussed further below.

The municipal utility has various energy goals, articulated in its long-term strategic plan, that support DER investments in the form of incentives for EE, DR, and building electrification upgrades. The municipal utility's programs are assumed to be approved by a governing board/council. Beyond the overarching goals of providing safe, reliable and reasonably priced electricity and gas services, the jurisdiction also has goals to:

- Reduce GHG emissions;
- Account for all fuels, in particular associated with avoided natural gas;
- Improve public health by improving air quality impacts (i.e., PM, SO₂, NO_x);
- Promote beneficial electrification, including programs that enable fuel switching;⁹ and
- Comply with state's RPS to diversify the generation mix, including an increase in renewable energy (RE) over time.¹⁰

The municipal utility's goals inform the "regulatory perspective" and the impacts accounted for in the jurisdiction's primary cost-effectiveness test – the JST. In this case, the JST includes:

- All electric utility system impacts, including environmental compliance costs associated with GHG emission reductions and criteria air pollutants;
- Gas utility system impacts, specifically avoided natural gas costs;¹¹
- Host customer impacts;
- Societal impacts associated with changes in GHG emissions over and above the cap-and-trade compliance costs (accounted for in utility system impacts); and
- Societal impacts associated with improved (or reduced) public health impacts due to changes in air quality impacts.

⁸ For additional information, see: <https://www.pjm.com/>

⁹ Examples of jurisdictions with policies that promote programs that enable fuel switching is provided at: https://www.aceee.org/sites/default/files/pdfs/fuel_switching_policy_brief_4-29-20.pdf

¹⁰ Efforts to "green the grid" may also be driven by utility commitments; see [SEPA's Utility Carbon Reduction Tracker](#) for more information. For additional information on states with RPS see: <https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx> and <https://emp.lbl.gov/publications/us-renewables-portfolio-standards-3>

¹¹ This case study only accounted for avoided natural gas costs (e.g., operations & maintenance) because it assumed that overall natural gas infrastructure and pipeline investments would not be impacted by the DER case. See [NSPM for DERs](#) Chapter 4.3 for a detailed description of gas utility and other fuel system impacts.

- A summary of the impacts included in the case study BCA is provided in Table 2 below, where the jurisdiction's primary cost-effectiveness test (i.e., its JST) reflects the respective policy goals of the hypothetical jurisdiction, consistent with NSPM Principle 2.

Table 2: Summary of Impacts Included in Residential GEB Retrofit Case Study

Category/Type	GEB Retrofit Case Study (JST)
Electric Utility System Impacts	All impacts included in JST though some values are zero where impact is not relevant to the use case and/or DER
Natural Gas Impacts / Other Fuel Impacts	Included in JST consistent with jurisdiction's policy
Host Customer Impacts	Included in JST consistent with jurisdiction's policy
Societal Impacts	GHG emission impacts (beyond any compliance costs) and public health impacts included consistent with jurisdiction's policy

3.2 Reference Case & Proposed Program Details

This case study assumes the following for its reference case and the DER case (GEB retrofit program), with further detail provided in Table 3:

- Reference case: Current residential customers modeled using an archetypal building energy model of a 2,500 square foot single family home with: SEER 10 central AC, 80% AFUE gas furnace, and no DR program participation ¹²
- DER case: Under the proposed DER case, residential customers would install combined EE, DR, and building electrification technologies:
 - EE: Upgrading ceiling insulation & reducing air leakage

¹² The residential building was modeled in EnergyPlus using RESstock, with regional average building specifications being the average values from RESstock probability distributions.

- Building electrification: Installing an ASHP¹³ to replace the natural gas furnace and central AC¹⁴
- DR: installing a smart thermostat with automatic enrollment in a DR program
- The program is assumed to be a 3-year program (2022-2024), with a 20-year analysis lifetime for all technologies (central AC, gas furnace, and ASHP). For technologies with lifetimes shorter than 20 years (central AC and ASHP of 16 years, thermostat of 11 years), the measure costs were annualized over the life of the measure and then continued for the remaining analysis period and scaled back to NPV to appropriately account for a 20-year analysis timeframe for all technologies.
- The replacement of the central AC and furnace was assumed to be a retrofit, with a remaining useful life of 6 years in the existing equipment. After the 6-year remaining useful life of the AC, the baseline SEER as assumed to be SEER 13 in compliance with the federal minimum for new units.

Table 3: Summary of Case Study Context and Key Assumptions

Assumption Category	Assumption Description	Value/Assumption
Utility & Grid Profile	Program Administrator	A municipal utility
	Location	Mid-Atlantic/PJM
	Regional Generation Mix	• Generation mix comparable to PJM market mix • Presence of coal-fired power plants in baseload with natural gas peaker plants
	Regional Energy Costs	• Moderate avoided energy and capacity costs which decline in the near term • Assumed the utility has a summer peak for program lifespan
Policy Context	Key Policy/Regulatory Objectives	• Policies to account for all fuels, promote beneficial electrification, including programs that enable fuel switching, and a state RPS to diversify the generation mix • Focus utility program regulation decisions on electric and gas utility system impacts, host customer impacts, and societal impacts (i.e., public health impacts - air quality) • Account for GHG impacts in utility decisions going forward

¹³ The ASHP was not assumed to be a cold climate heat pump.

¹⁴ The case study assumed installation of backup electric resistance strip heating.

Assumption Category	Assumption Description	Value/Assumption
Reference Case	Current Residential Home	A 2,500 sq. ft single family home with: central AC ¹⁵ a gas furnace, and no DR program participation
	Overall Housing Stock	Average RESstock home architectural parameters (i.e., roof insulation, window u-value) for Mid-Atlantic area and climate zone
DER Case (Proposed Program Details)	Program Offering	Retrofit installation of combined technologies: • EE: Upgrading ceiling insulation & reducing air leakage • Building electrification: Installing ASHP to replace the natural gas furnace and central AC¹⁶ • DR: installing a smart thermostat with automatic enrollment in a DR program
	Program Customer Type	Residential
	Program Offering Time Period/Length	3 years
	Measure Lifespan	20-year measure lifespan for all technologies (central AC, gas furnace, and ASHP). For technologies with lifetimes shorter than 20 years (central AC and ASHP of 16 years, thermostat of 11 years), the measure costs were annualized over the life of the measure and then continued for the remaining analysis period and scaled back to net present value to appropriately account for a 20-year analysis timeframe for all technologies. The replacement of the central AC and furnace was assumed to be a retrofit, with a remaining useful life of 6 years in the existing equipment. After the 6-year remaining useful life of the AC the baseline SEER as assumed to be SEER 13 in compliance with the federal minimum for new units.
	Number of NEW Participants Each Year	Year 1: 500 Year 2: 1,000 Year 3: 1,500
	Financial Incentive for Participants	Incentive calculated to cover 40% of the incremental cost of the upgrades, resulting in \$2,000 per participant
	Program Administrator Cost	Assumed a 30/70 split between program administration and financial incentive costs, aligned with industry standard for EE

¹⁵ The AC baseline assumption included a constant thermostat setpoint of 72 degrees F over the summer.

¹⁶ Even without a winter peak, non-average weather conditions may require electric resistance back-up heat. The case study assumed backup electric resistance strip heating based on 3-year typical meteorological year (TMY) and weather data for southern Maryland.

Assumption Category	Assumption Description	Value/Assumption
		programs
	Discount Rate	A real discount rate of 2.6% was selected based on the time preference of the regulator reflecting a societal point of view. The SCC values with the closest discount rate (2.5%) were used to align this value stream with the rest of the modeling.

3.3 Impacts Analyzed and Data Approach

Based on this jurisdiction's JST, and the description of the reference case and use case for the GEB Retrofit program, Tables 4-7 below indicate:

- Which utility and non-utility system impacts are accounted for in the analysis;
- Where and how interactive effects across the DERs affect specific impacts;
- Where/how the DER operating profiles were estimated; and
- The associated data sources and approach used to quantify the impacts.¹⁷

While all utility system impacts are part of the jurisdiction's primary JST, some impacts have values of zero in the BCA either because the impact is not relevant to the DER and/or use case or is immaterial in impact.

Table 4: Electric Utility System Impacts

Type	Specific Impact	Data Description & Rationale
Generation	Energy Generation	Calculated using hourly (8760) avoided energy data from a Mid-Atlantic utility and Guidehouse EmPower Maryland 2019 Cost-Effectiveness report. Hourly data is necessary to capture the impact of the load shift on energy generation, which would not be picked up by annual or monthly avoided cost data. These costs levelize the environmental compliance with Regional Greenhouse Gas Initiative (RGGI) and DRIPE value streams.
	Capacity	Calculated using a bundled generation, transmission, and distribution capacity cost from <i>Guidehouse EmPower Maryland 2019 Cost-Effectiveness</i> report, with generation and T&D capacity separated based on ratios from Exeter Avoided Energy Costs in Maryland 2014 report. ¹⁸

¹⁷ For more information about conducting the BCA for DERs for multiple on-site DERs, please reference the [NSPM for DERs](#) Chapter 11. For information on methods used to conduct BCA for electric system, host customer, societal, and reliability and resilience impacts, see Chapters 3, 6, 7, and 8 of the [MTR Handbook](#).

¹⁸ Source: https://www.ilsag.info/wp-content/uploads/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/Followup_Documents/AvoidedEnergyCostsinMaryland1.pdf

Type	Specific Impact	Data Description & Rationale
	Environmental Compliance	Accounted for within avoided energy generation costs, which include both clean air environmental regulation costs and the cost of complying with RGGI.
	RPS/CES Compliance	Costs associated with procuring a reduced amount of RECs calculated using Exeter Avoided Energy Costs in Maryland 2014 report. ¹⁹
	Market Price Effects	The market price impacts, also known as DRIPE, are already accounted for in the avoided energy costs, and were not modeled as a separate value stream.
	Ancillary Services	California Avoided Cost Calculator 2020 data was utilized assuming ancillary services of 0.9% of avoided energy costs.
Transmission	Capacity	Calculated using a bundled generation, transmission, and distribution capacity cost from Guidehouse EmPower Maryland 2019 Cost-Effectiveness report, with generation and T&D capacity separated based on ratios from Exeter Avoided Energy Costs in Maryland 2014 report. ²⁰
	System Losses	Transmission line loss rates were accounted for within avoided energy and capacity impacts. There are no additional impacts for this particular analysis such as changes in line loss rates as a result of DER implementation.
Distribution	Capacity	Calculated using a bundled generation, transmission, and distribution capacity cost from Guidehouse EmPower Maryland 2019 Cost-Effectiveness report, with generation and T&D capacity separated based on ratios from Exeter Avoided Energy Costs in Maryland 2014 report. ²¹
	System Losses	Distribution line loss rates were accounted for within avoided energy and capacity impacts. There are no additional impacts for this particular analysis such as changes in line loss rates as a result of DER implementation.
	O&M	While part of the JST for this jurisdiction, no value is included for this impact because there are no distribution O&M impacts from this program.
	Voltage	While part of the JST for this jurisdiction, not relevant for this use case as there are no distribution voltage impacts.
General	Financial Incentives	Incentive was calculated to cover 40% of the incremental cost of the upgrades, resulting in \$2,000 per participant.

¹⁹ Source: https://www.ilsag.info/wp-content/uploads/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/Followup_Documents/AvoidedEnergyCostsinMaryland1.pdf

²⁰ Source: https://www.ilsag.info/wp-content/uploads/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/Followup_Documents/AvoidedEnergyCostsinMaryland1.pdf

²¹ Source: https://www.ilsag.info/wp-content/uploads/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/Followup_Documents/AvoidedEnergyCostsinMaryland1.pdf

Type	Specific Impact	Data Description & Rationale
	Program Administration Costs	Program administration cost is calculated based on a 30/70 split between program administration and financial incentive costs, which is within industry standard range for EE programs.
	Utility Performance Incentives	Not part of the JST for this jurisdiction because policy does not support utility performance incentives.
	Credit and Collection Costs	While part of the JST for this jurisdiction, no value is included because there are no credit and collections costs in this market-rate program.
	Risk	To quantify the value from risk reduction, a percent adder method was utilized. A 5% adder for risk was utilized to account for the reduced risk of hedging against future escalation in energy prices. This shows up as a benefit for gas since gas consumption is reduced, but a cost for the electric side due to the higher electric loads. The key sources for the 5% adder were Energy Trust of Oregon and DC Sustainable Energy Utility. ²²
	Reliability	While part of the JST for this jurisdiction, no value included because the DER doesn't reduce utility expenditures on reliability. ²³
	Resilience	While part of the JST for this jurisdiction, no value included because the DER doesn't have a meaningful impact on utility system resilience.
Other	Other - DERMS	Calculated based on industry analysis of procurement costs of a Distributed Energy Resource Management System (DERMS) platform for DR events.

Table 5: Gas Utility System & Other Fuel Impacts

Type	Gas Utility System Impact	Data Description & Rationale
Energy/Supply	Fuel and Variable O&M	Avoided cost of natural gas including the T&D costs to residential properties based on ICF modeling for a client in the Mid-Atlantic: \$7 / MMBTU, includes natural gas energy, T&D costs, and market price effects.
	Capacity (e.g., local storage)	While this value stream is conceptually part of the JST for this jurisdiction, no value is included for this impact due to flatlined natural gas demand and no viable savings from reducing size of gas capacity in the ground.
	Environmental Compliance	Accounted for in avoided cost per therm.

²² Sources: [Oregon: ETO. Energy Trust Electric and Gas Avoided Cost Update for Oregon for 2018 Measure and Program Planning](#), and DC: VEIC, DCSEU Multiyear contract, Contract No. DOEE-2016-C-002, section C.40.10.5 at [DCSEU Multiyear Contract Final \(003\).pdf - Google Drive](#)

²³ Reliability metrics including SAIDI, SAIFI, or CAIDI inform a utility's annual reliability performance and expenditures. No additional reliability impacts are quantified since the program would not improve utility metrics like SAIDI, SAIFI, or CAIDI outside of those impacts related to generation, transmission, and/or distribution overages which are accounted for in the avoided generation, transmission and distribution capacity impacts.

Type	Gas Utility System Impact	Data Description & Rationale
Transportation	Market Price Effects	While part of the JST for this jurisdiction, no values are included for these impacts either because not relevant to the DER/use case or the impact is already accounted for implicitly in other value streams.
	Pipeline Capacity	
	Pipeline Losses	
Delivery	Local Delivery Capacity	
	Local Delivery O&M	
General	Financial Incentives	
	Program Admin Costs	
	Performance Incentives	
	Credit and Collection Costs	
	Risk, Reliability, Resilience	

Type	Other Fuel Impacts (other fuels include oil, propane, wood, and gasoline)	Data Description & Rationale
Other Fuels	Fuel and O&M	While part of the JST for this jurisdiction, no value is included as there are no impacts associated with this use case.
	Delivery Costs	
	Environmental Compliance	
	Market Price effects	

Table 6: Host Customer Energy & Non-Energy Impacts

System Impact	Specific Impact	Data Description & Rationale
Host Customer Energy Impacts	Host Portion of DER/Measure Costs – Incremental Capital Costs	Calculated using state technical reference manuals to estimate increased capital cost to procure EE, DR, and building electrification measures. ²⁴ A total host incremental cost of \$5,000 per participant was calculated for all measures, less the \$2,000 utility incentive for a net host customer cost of \$3,000.
	Host Transaction Costs – Electric Service Upgrade Costs	Calculated using online information to estimate the average cost associated with procuring a higher amperage electric panel to support the electrification measures, assuming replacement of a 100 Ampere panel with a 200 Ampere panel with a breaker. ²⁵
	Interconnection Fees	While part of the jurisdiction’s JST, no value included because there are no interconnection fees associated with this DER program / use case.
	Risk	

²⁴ Sources: [Michigan Energy Measures Database](#), and [Illinois Technical Reference Manual \(TRM\) volume 9, New Orleans Technical Reference Manual V4.0 \(entergy-neworleans.com\)](#)

²⁵ Source: [HomeGuide](#)

System Impact	Specific Impact	Data Description & Rationale
	Reliability	While part of the jurisdiction's JST, no value included because there are no impacts associated with this DER program / use case.
	Resilience	
	Tax Incentives	
Host Customer Non-Energy Impacts	O&M	Calculated using an estimated O&M cost of \$100/year for central AC plus \$150/year for gas heating (a total of \$250/year) displaced by the ASHP, with an estimated annual O&M cost of \$100, resulting in net O&M benefits of \$150 per year. ²⁶
	Asset Value	To quantify the value from host customer non-energy impacts generally, a proxy adder method was utilized. A 5% proxy adder based on avoided energy, avoided generation capacity, avoided T&D capacity, and avoided natural gas costs. ²⁷
	Productivity	
	Economic Well-being	
	Comfort	
	Health & Safety	
	Empowerment & Control	
	Satisfaction & Pride	

Table 7: Societal Impacts

Specific Impact	Data Description & Rationale
Resilience	N/A – not reflected in the jurisdiction's applicable policies and JST.
GHG Emissions	Societal benefits in GHG emissions reduction was modeled using the U.S. EPA SCC, and Long Run Marginal Emissions Intensity for Maryland from NREL Cambium tool (mid case).
Other Environmental Impacts	N/A – not reflected in the jurisdiction's applicable policies and JST.
Public Health	The public health impacts for the EE, DR, and building electrification measures were quantified using the U.S. EPA Metrics for public health benefits by changing PM2.5, SO2 and NOX emissions. Sources included U.S. EPA COBRA , U.S. EPA BPK, and U.S. EPA Natural Gas Emission Factors.
Economic Development and Jobs	N/A – not reflected in jurisdiction's applicable policies and JST.
Energy Security	N/A – not reflected in jurisdiction's applicable policies and JST.

Several impacts from the tables above warrant some additional explanation and context, as described below.

Accounting for GHG Emissions: - The treatment of GHG emission impacts requires distinguishing between environmental compliance impacts (within utility system impacts) and societal environmental impacts in order to conduct BCA tests²⁸:

²⁶ Sources: [Illinois Technical Reference Manual \(TRM\) volume 9](#) and [NYSERDA Heat Pump Study \(2019\)](#)

²⁷ Source: Based on Washington, D.C.'s proxy adder in [ACEEE. Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency. Dec 2018](#)

²⁸ See [MTR Handbook](#) - Chapter 3.2.6 and Chapter 7.1.

- Environmental compliance impacts are the direct impacts in dollar terms that will be incurred by the utility and passed on to all customers through revenue requirements and customer rates. Environmental compliance impacts are utility system impacts that will be paid by utility customers and therefore should be included in all BCA tests.
- Societal environmental impacts are imposed on society as a whole but do not affect the cost of electricity services. Societal environmental impacts do not reflect direct costs that will be paid by utility customers and therefore should be included only in a BCA test if that would be consistent with the jurisdiction's policy goals.²⁹

Due to the hypothetical jurisdiction's policies such as participation in RGGI, it is assumed that the utility is on the path toward decarbonization, but that the path is not aggressive enough to alleviate all potential societal damage costs as a result of carbon emissions. Therefore, the GEB Retrofit case study accounts for the MAC of GHG emissions within utility system impacts (through RGGI compliance costs) as well as accounting for damage costs from GHG emissions within societal impacts using a SCC for valuation (see Tables 4-7 for data description). Double counting is avoided by assuming that the GHG emissions rates used for calculating the damage cost estimates are aligned with the planned decarbonization pathway, so that MAC and damage cost components do not overlap.

Societal GHG emissions were calculated using the U.S. EPA SCC, and NREL Cambium tool (mid case) for long run marginal emissions intensity. The social cost of carbon impacts were calculated at an hourly granularity using annual SCC values multiplied by hourly emissions rates from Cambium and hourly load impact estimates from simulating the upgrade package in EnergyPlus.

Accounting for Avoided Generation, Distribution and Transmission Capacity Costs - Changes in electric demand were averaged across all annual system peak hours to determine an average annual peak reduction value (kW). This value is then used to determine avoided T&D costs, and avoided generation capacity costs using data from the Guidehouse EmPower Maryland 2019 Cost-Effectiveness report, and Exeter [Avoided Energy Costs in Maryland 2014](#) report. In this case study, the average annual peak reduction value is 1.95 kW per customer and is due to both reductions in demand (EE and the switch from a central AC unit to a more efficient ASHP) and the shifting of demand (by the smart thermostat DR enrollment).

Accounting for Public Health Benefits - The public health impact stream is calculated using the EPA's COBRA³⁰ tool to estimate public health impacts for criteria air pollutants (including PM2.5, SO2 and NOX). For the natural gas impacts, the \$/pollutant impacts from natural gas combustion were multiplied by the emissions rates for each pollutant and change in gas consumption to determine the total impacts. For the electric impacts, EPA's Health Benefits per kWh of efficiency (BPK)³¹ was utilized as it is built upon estimates from the COBRA tool. However, to properly account for greening of the grid, the \$/kWh from the BPK tool was scaled to reflect the decrease in long-run marginal emission rates of criteria emissions as the grid

²⁹ See [MTR Handbook](#) - Chapter 3.2.6 and Chapter 7.1.

³⁰ Source: <https://www.epa.gov/cobra>

³¹ Source: <https://www.epa.gov/statelocalenergy/estimating-health-benefits-kilowatt-hour-energy-efficiency-and-renewable-energy>

decarbonizes. To do this the Cambium projections of GHG long-run marginal emissions were assumed to reflect the same scaling that could be assumed for criteria emissions, a conservative assumption since criteria emissions will likely decrease faster due to the disproportionate impacts of coal plants on criteria emissions.

4. BCA Results

4.1 Summary of Inputs & Calculated Values

As outlined in Tables 4-7, various utility system, host customer, and societal impact streams are used to calculate the net benefits of the proposed program, with key input variables summarized below and BCA results presented in Table 8:

Table 8: Summary of Relevant Value Streams for JST

<i>Summary of Relevant Value Streams for Jurisdiction-Specific Test*</i>			
Electric Utility System Impacts	Gas Utility System Impacts	Host Customer Impacts	Societal Impacts
• Avoided Energy Costs • Avoided Generation Capacity Benefits • Avoided RPS/CES Compliance Costs • Avoided Ancillary services Costs • Avoided T&D Capacity Benefits • Utility Financial Incentives Costs • Utility Program Administration Costs • Avoided Risk Benefits • DERMs Cost	• Avoided Natural Gas Fuel and Variable O&M Benefits	• Incremental Capital Costs • Electric Service Upgrade Costs • Host Customer O&M Benefits • Host Customer Non-Energy Impacts	• Avoided GHG Emissions Benefits • Public Health Impacts

*As noted in Tables 4-7, some impacts that are part of the jurisdiction's primary JST are not included in the BCA because either the impact is not relevant to this use case or is immaterial in impact.

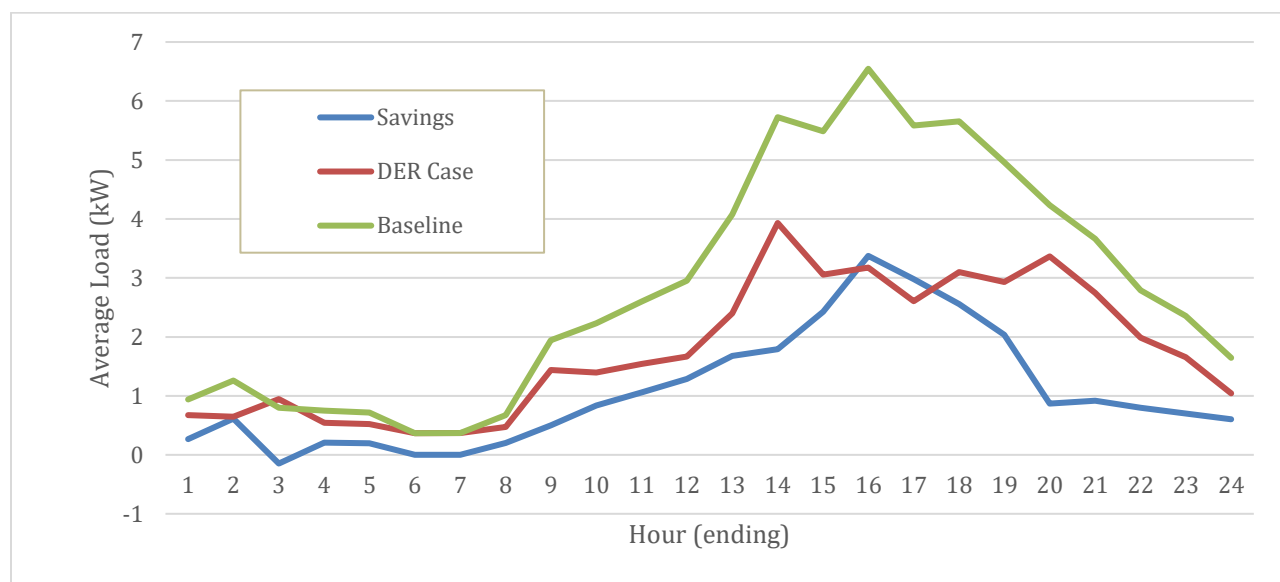
Load Shape Analysis & Interactive Effects

Calculating the values for many of these impact streams requires estimating the changes in electric and natural gas load shapes on a per participant per hour of year basis. This is accomplished by subtracting the expected heat pump with EE and DR load shapes (for electric and natural gas) from the baseline electric and natural gas load shapes of the home. The heat pump with smart thermostat and weatherization load shapes, as well as the baseline load shapes were created using DOE's [EnergyPlus](#) whole building energy simulation tool and expert judgement by ICF. Interactive effects are taken into account through DOE's EnergyPlus tool by implementing multiple measures in a single building energy model. However, this case study

also modeled each measure upgrade separately in EnergyPlus and added the results to demonstrate the significant differences caused by not accounting for interactive effects.

Within the calculations, it is assumed that all natural gas use is eliminated by switching to a heat pump system. Electricity consumption increases as a result but is mitigated by weatherization and smart thermostat DR participation. The DR participation is assumed to shift 0.5 kW of load away from system peak hours on average during the summer, which is on the lower end of the spectrum for estimates due to the absence of precooling prior to the DR event period. The overall electric system is assumed to maintain a summer peaking system throughout the program's life.

Figure A: GEB Retrofit Load Shape Analysis: Baseline and DER Case



Discount Rate

A real discount rate of 2.6% was selected based on the time preference of the regulator reflecting a societal point of view. The SCC values with the closest discount rate (2.5%) were used to align this value stream with the rest of the modeling. For more information on using an appropriate discount rate see Chapter 5-11 and Appendix G of the [NSPM for DERs](#).

All calculated values are shown below and are placed into comparable monetary units (NPV in 2021 dollars).

Table 9: GEB Retrofit JST: BCA Values and Results

Value Stream	Net Present Value (\$ 2021)
ELECTRIC UTILITY SYSTEM	
Avoided T&D Capacity	\$ 1,866,911
Avoided Generation Capacity	\$ 6,924,649
Avoided Energy	\$ (8,876,210)
Avoided Ancillary Services	\$ (79,886)

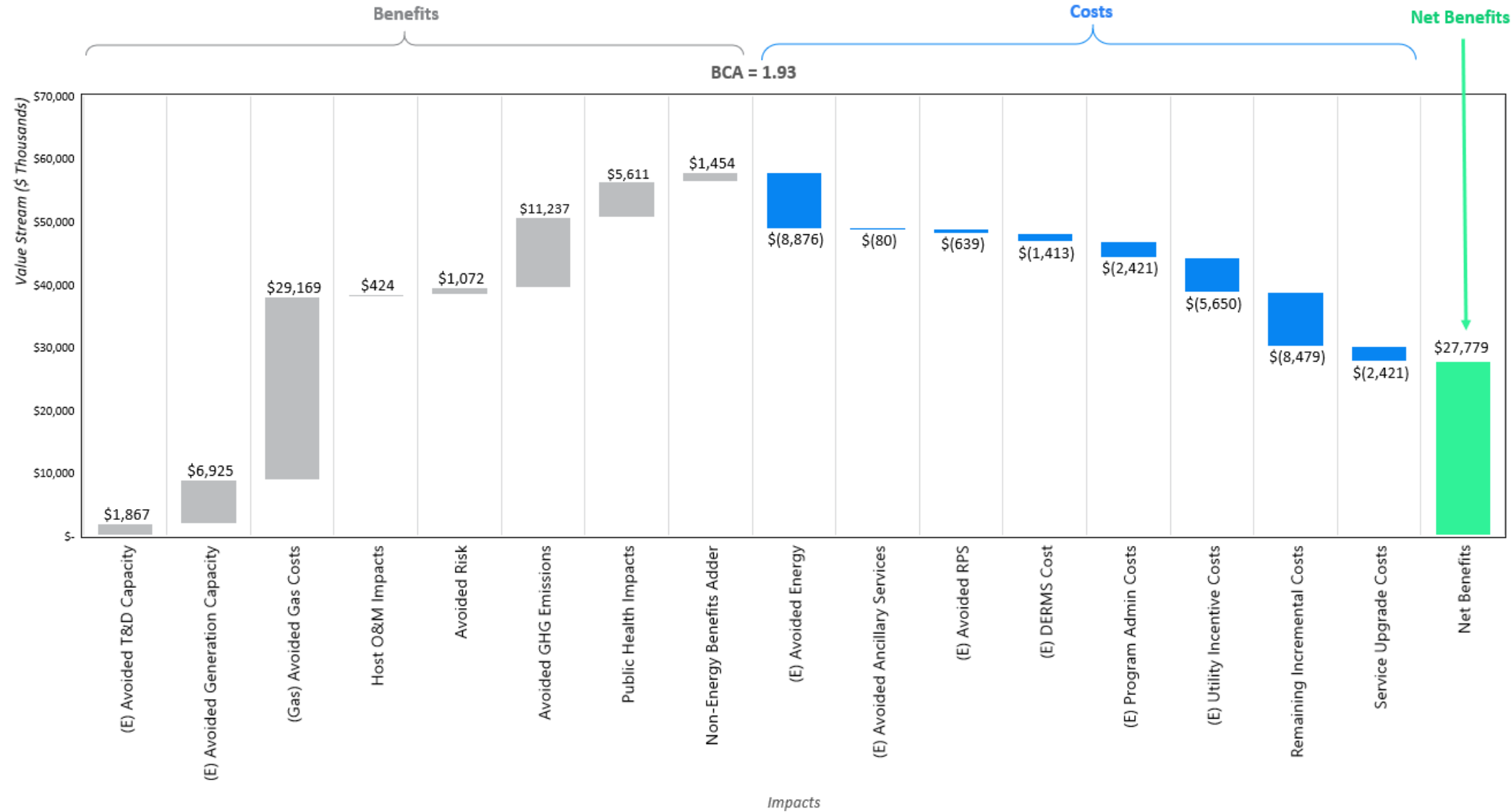
Value Stream	Net Present Value (\$ 2021)
Avoided RPS	\$ (638,865)
Program Admin Costs	\$ (2,421,464)
Utility Incentive Costs	\$ (5,650,084)
Other - DERMS Cost	\$ (1,412,521)
GAS UTILITY SYSTEM	
Avoided Gas Costs	\$ 29,168,780
HOST CUSTOMER	
Host Incremental Costs (net of incentives)	\$ (8,479,133)
Host O&M Impacts	\$ 423,756
Service Upgrade Costs	\$ (2,421,464)
Avoided Risk	\$ 1,072,037
Non-Energy Benefits Adder	\$ 1,454,207
SOCIETAL IMPACTS	
Avoided GHG Emissions	\$ 11,237,119
Public Health Impacts	\$ 5,610,915
Total Benefits	\$ 57,758,374
Total Costs	\$ (29,979,627)
Net Benefits	\$27,778,746
Benefit-Cost Ratio	1.93

The benefit-cost ratio of this program is 1.93, with net benefits of \$27,778,746. With a benefit-cost ratio greater than 1.0, the proposed program is cost-effective.

This case study modeled the interactive effects of implementing multiple measures in a single building energy model, and also modeled each measure upgrade separately to demonstrate the significant differences caused by not accounting for interactive effects.

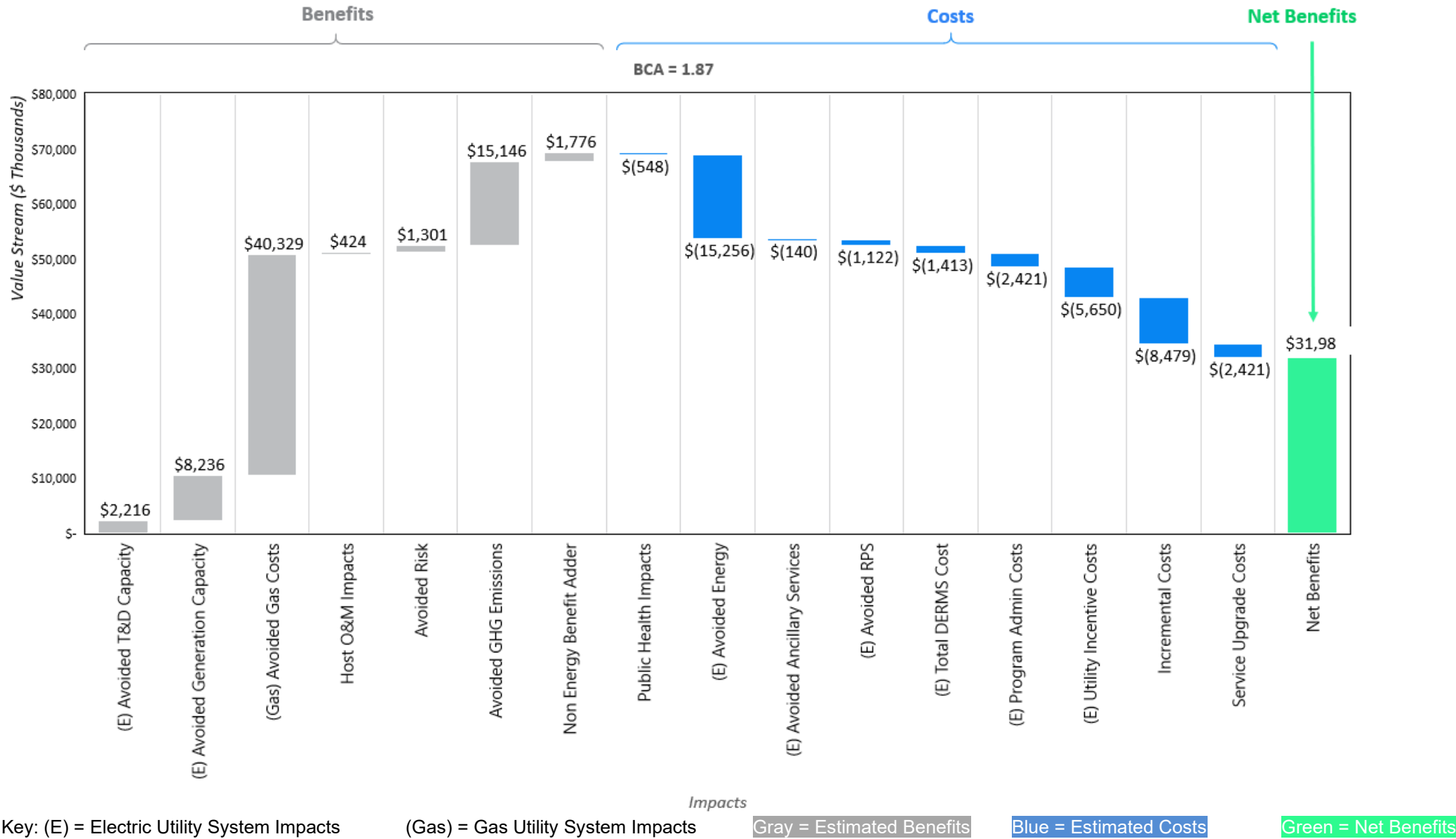
Figure B illustrates the BCA results with interactive effects included, while Figure C shows the BCA results with interactive effects *not* included, with a benefit-cost ratio of 1.87 and net benefits of \$31,975,978.

Figure B: GEB Retrofit JST: BCA Value Streams and Net Benefits - Individual GEB Measures Combined - Interactive Effects Included



Key: (E) = Electric Utility System Impacts (Gas) = Gas Utility System Impacts Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

Figure C: GEB Retrofit JST: BCA Value Streams and Net Benefits - Individual GEB Measures Combined - Interactive Effects NOT Included



4.2 Summary of Key Factors and Findings

The key factors and findings from this GEB Retrofit case study are as follows:

Accounting for Interactive Effects

- It is important to note that accounting for interactive impacts is a key component in multi-DER BCAs. As shown in the Analysis Results section above, both electric and gas impacts can be overestimated if interactive effects are not properly considered. Had interactive effects not been properly accounted for in this case study, net benefit estimates would have been higher than reality.³²

This waterfall graph shows the sum of individually modeled program measures. Impact streams such as program administration costs that do not use data from the EnergyPlus tool as an input are the same in this graph and the graph above which accounts for interactive effects.

Utility Electric System Impacts

- On the cost side of the analysis, incremental retrofit and electric service upgrade costs are key drivers. Since these cost estimates can vary widely depending on the counterfactual assumptions used (e.g., remaining useful life and existing panel sizes), care should also be taken to ensure that assumptions are defensible. In addition, the cost of electricity generation made the energy efficiency measures of the program valuable as a means of decreasing the cost side of the BCA. However, as avoided electricity costs decrease with increasing renewable energy penetration, the EE measures may become less impactful in the BCA result.

Utility Natural Gas & Other Fuel Impacts

- Avoided gas costs are a key driver of benefits for this proposed program. The cost-effectiveness ratio is also very sensitive to the assumptions used to determine the avoided gas costs. Therefore, due diligence should be paid to gas input assumptions to ensure that benefit-cost ratio findings are robust.

Societal Impacts

- This case study highlights how switching from a natural gas furnace to an electric heat pump can have complex public health impacts on air quality. Depending on the resource mix of the electric grid, more societal PM, NOx and SO2 emissions may initially be generated by a switch to electricity. However, the assumed trajectory of the grid's transition to non-emitting generation will play a large role in determining if the switch results in societal benefits or costs. Combining the fuel switch with DR and EE measures can also influence the calculation.

³² The hypothetical DER use case includes measures that both add electric load (i.e., electrification measures) and reduce electric load (i.e., EE and DR measures), which impacts the overall potential value of interactive effects.

Overall, the JST's high benefit-cost ratio (1.93) is driven by avoided gas costs and avoided GHG emissions, in addition to accounting for interactive effects between DERs. As utilities, regulators, and customers increasingly focus on building electrification, including retrofits, accounting for interactive effects will be a critical component for BCA.

4.3 Conclusions and Areas for Further Research

This case study demonstrates the importance of accurately accounting for interactive impacts of DERs. While historically DERs have often been analyzed in isolation due to their low penetration rates, aggressive decarbonization goals in the coming decades will likely push penetration levels of DERs significantly higher. Therefore, it will be increasingly critical for regulators and utilities to capture the interactive impacts between EE, DR, and other DERs in BCA.

Another key takeaway from this case study is the need to model changes in influential inputs over time, as illustrated by the GHG value stream. Whereas in the EV managed charging case study the DER minimized the impacts of the GHG value stream, and so did not necessitate an accurate forecast of grid decarbonization, here the opposite is true since electrification is one of the key DERs considered. Due to the assumed significant greening of the grid over time, electrification offers a much larger benefit to the JST than if the grid emissions rates were assumed to be consistent. This point is often relevant for GHG emissions, but also holds true for value streams such as criteria air emissions.

This also highlights one of the key areas for additional research: if and when the gas system will be able to decarbonize. This analysis assumes that the gas system will not decarbonize over the next 20 years, however, there are already dual fuel utilities (such as Xcel Colorado) which have committed to having carbon-free electricity and gas in the coming decades. A jurisdiction's assumptions on gas decarbonization will have a significant impact on their decision making as decarbonization becomes a focal point for governments and utilities.

5. Additional Considerations

5.1 DER Use Case Impact

As illustrated in this case study, benefit-cost results are heavily dependent on the DERs and use cases being examined, as well as the specific policy and utility scenarios that determine the JST. The influence of the “full picture” and comprehensive value streams that the NSPM for DERs sets forth for utility system impacts and other impacts (depending on a jurisdiction’s policy situation) can have very significant impacts on cost-effectiveness. In addition, when considering BCA results, care should be taken to ensure that the level of precision achieved for each value stream is proportional to the absolute value of the stream and is reflective of the uncertainty found within a value stream’s inputs.

5.2 Accounting for Hard to Quantify Impacts

The NSPM sets forth that if an impact is relevant to a jurisdiction’s JST *and the specific use case*, then it should be accounted for as the value is not zero. Exceptions may be where the impact is immaterial, or the cost of obtaining accurate data for quantifying the value stream is not proportional to the scale of the impact.

Therefore, when making investment decisions, it is critical that qualitative and non-monetized impacts be considered in addition to quantitative BCA results. A calculated BCA is rarely representative of all critical factors and should not be used as a binary decision-making algorithm. Instead, expert judgment is usually needed to determine the appropriate, relative scale and weighting of qualitative and non-monetized impacts relative to BCA results. Nevertheless, a JST with relevant secondary tests does serve as a strong foundation from which to layer on qualitative and non-monetized impacts. Methods such as applying adders to BCA impact streams and running sensitivity analyses can also help to show how BCAs may change under different scenarios. For further information, see the [MTR Handbook](#).

Appendix – BCA Impact Categories

Electric Utility System Impacts³³

Type	Utility System Impact	Description
Generation	Energy Generation	Production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	Generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The change in wholesale market prices as a result of changes in customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs programs or strategies
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

³³ Tables and descriptions are from the [NSPM for DERs](#).

Gas Utility System and Other Fuel Impacts

Type	Gas Utility System Impact	Description
Energy/Supply	Gas Commodity	The gas capacity required to meet forecasted peak load as well as the fuel and Operations & Maintenance (O&M) impacts associated with gas
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The change in wholesale prices as a result of changes in customer consumption
Transportation	Pipeline Capacity	The fixed charges for pipeline transportation services that deliver natural gas to the local distribution company (LDC) city gate
Distribution	Pipeline Losses	The volumetric difference between the gas entering the LDC city gate and the gas measured at customers' meters
	Gas Distribution	Local distribution company costs to deliver gas from the city gate to retail customers
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration Costs	Costs incurred by the DER program administrator related to the planning, design, implementation, and evaluation of a DER program or initiative
	Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection Costs	Costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, terminations, disconnections, reconnections, carrying costs associated with arrears and writing off bad debt.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining the gas system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Other Fuel Impacts

Type	Other Fuel Impact (oil, propane, wood, gasoline)	Description
Other Fuels	Commodity	The fuel and O&M impacts associated with other fuels
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The change in wholesale prices as a result of changes in customer consumption

Host Customer Impacts

Host Customer Impact	Description
Energy Related Impacts	
Host Portion of DER Costs	Costs incurred to install and operate DERs
Interconnection Fees	Costs paid by host customer to interconnect DERs to the grid
Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk can depend on the type of DER
Reliability	The ability to prevent or reduce the duration of host customer outages
Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
Tax Incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
Non-Energy Impacts (NEIs)	
Transaction Costs	Costs incurred to adopt DERs, beyond those related to installing or operating the DER itself (e.g., application fees, customer time spent researching DERs, paperwork, etc.)
Asset Value	Changes in the value of a home or business as a result of the DER (e.g., increased building value, improved equipment value, extended equipment life)
Productivity	Changes in a customer's productivity (e.g., in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
Economic Well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
Health & Safety	Changes in customer health or safety (e.g., fewer sick days from work, reduced medical costs, improved indoor air quality, reduced deaths)
Empowerment & Control	Satisfaction of being able to control one's energy consumption and energy bill
Satisfaction & Pride	Satisfaction of helping to reduce environmental impacts (e.g., key reason why residential customers install rooftop PV)

Societal Impacts

Societal Impact	Description
Resilience	Resilience impacts beyond those experienced by utilities or host customers
GHG Emissions	GHG emissions created by fossil-fueled energy resources
Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
Public Health	Health impacts, medical costs, and productivity affected by health
Energy Security	Energy imports and energy independence