Benefit-Cost Analysis Case Studies

Examples of Distributed Energy Resource Use Cases

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A Compendium to the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources

NATIONAL ENERGY SCREENING PROJECT

Table of Contents

Acknowledgements

National Energy Screening Project

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The BCA Case Studies report serves as a companion document to the 2020 *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which presents the NSPM Benefit-Cost Analysis (BCA) Framework, fundamental BCA principles, and guidance specific to determining primary and secondary BCA tests.

This report and related NESP materials, including the NSPM for DERs, are available at: www.nationalenergyscreeningproject.org

Report Authors

This manual was prepared by the following project team:

- Smart Electric Power Alliance – Kate Strickland and Becca Trietch
- ICF – David Pudleiner, Abhishek Jain, and Katie Van Horn

The Project was coordinated by Julie Michals at E4TheFuture.

Peer Reviewers

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General Review

- Chris Neme, Energy Futures Group
- Karl R. Rábago, Rábago Energy
- Tim Woolf, Synapse Energy Economics

Electric Vehicle and Solar + Storage Case Studies

- Ookie Ma, Office of Energy Efficiency & Renewable Energy - US DOE
- Steven Rymsha, Sunrun
- Tim Nelson, Evergy
- Jeremy Twitchell, Pacific Northwest National Laboratory

Grid-interactive Efficiency Building Case Study

- Andy Eiden, Portland General Electric
- Natalie Mims Frick, Lawrence Berkeley National Laboratory
- Rodney Sobin, National Association of State Energy Offices
- Sheldon Switzer, Baltimore Gas & Electric

Introduction and Overview of Case Studies

The purpose of this report is to illustrate benefit-cost analyses (BCAs) for various distributed energy resource (DER) technologies and use cases that are of growing interest in the electric industry. It presents three case studies that apply guidance from the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* ("NSPM").[1]

The three case studies are:

1. *Residential EV Managed Charging in the Midwest*
2. *Commercial Solar + Storage Controlled Dispatch in the West*
3. *Residential Grid-interactive Efficient Building Retrofit in the Mid-Atlantic*

Each case study is informed by real-world BCAs and data for similar use cases but have been generalized into illustrative and hypothetical examples for broader applicability. The case studies are based on different cost-effectiveness tests that align with the specific policy goals and objectives for the three hypothetical jurisdictions. In addition, each case study illustrates key BCA considerations for either single or multi-DER use cases and demonstrates different approaches to account for impacts when certain data may be unavailable.[2] Finally, different regions of the U.S. were used for each case study to highlight how different policy and grid contexts can influence the BCA.

Case Study 1: Residential EV Managed Charging in the Midwest

The residential electric vehicle (EV) managed charging case study considers a hypothetical incentive for level II EV chargers coupled with a time-of-use (TOU) rate. The program is assumed to be provided by an investor-owned utility (IOU) located in the Midwest. This case study was developed to demonstrate key factors and challenges with conducting BCA for a managed charging program offered to existing EV owners.

Case Study 2: Commercial Solar + Storage Controlled Dispatch in the West

The commercial solar + storage controlled dispatch case study considers a hypothetical commercial behind-the-meter (BTM) solar + storage program that provides an incentive for a battery energy storage system (BESS) when paired with a solar photovoltaic (PV) system, and enrollment in a TOU rate. The program is assumed to be provided by an IOU in the Western US region. This case study was developed to demonstrate key factors and challenges with BCAs for distributed generation (DG) and distributed storage resources in a multiple on-site DER use case.

Case Study 3: Residential Grid-interactive Efficient Building Retrofit in the Mid-Atlantic

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

[2] 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.

The residential grid-interactive efficient building (GEB) retrofit case study considers a hypothetical 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. This case study was developed to demonstrate key factors and challenges with BCAs for a combined weatherization (e.g., energy efficiency (EE)), demand response, and building electrification program.

All three case studies align with the fundamental NSPM BCA principles summarized in Table I. These principles are foundational to ensuring that BCAs are conducted in an economically-sound manner.

Table I: 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 Imapcts** 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 Analysis** 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.

DER Impact Categories and Definitions

The key impact categories for DER BCAs are generally electric utility system impacts, natural gas utility and/or other fuel impacts, host customer impacts, and societal impacts. The range of impacts within each category, and associated definitions, are provided in the Tables II-V below.[3]

Table II: Electric Utility System Impacts

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

[3] Tables and descriptions are from the NSPM for DERs.

Type	Utility System Impact	Description
	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

Table III: 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

Table IV: 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 labor costs, operational flexibility, O&M impacts (including impacts on other energy sources and water and wastewater costs as well as reduced maintenance [e.g., because of longer lives of LEDs]), increased production improved product quality, reduced waste streams, reduced spoilage, etc.
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)

Table V: 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
Economic and Jobs	Incremental economic development and job impacts
Public Health	Health impacts, medical costs, and productivity affected by health
Energy Security	Energy imports and energy independence

Each case study considers the full range of electric utility system impacts (Table II) to ensure that the DERs are treated as a resource, consistent with NSPM Principle 1 (Table I). In some cases, depending on the DER, use case or profile of the jurisdiction (e.g., whether in an organized market or not), some impacts may not apply.

The extent to which any other impact categories (other fuel, host customer, and/or societal impacts in Tables III-V) apply to the case study BCAs depends on the applicable policy goals of each hypothetical jurisdiction, consistent with the "regulatory perspective" described in the NSPM (and NSPM Principle 2). As such, each 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).[4]

The case studies intentionally assume that the policy goals in each of the three hypothetical jurisdictions vary, to illustrate how different policies inform or translate to different JSTs.

Accounting for Energy Equity: While many states increasingly are addressing energy equity as a key policy goal, the case studies do not address equity policies. This is because BCAs do not inherently account for energy equity. Rather, energy equity is better addressed through complementary distributional equity analyses (DEA), which can include rate and bill impact analyses, energy burden, and other analyses that compare distributional effects. DEAs are beyond the scope of this report. For more information, see Chapter 9 of the MTR Handbook.

A summary of the impacts included in the three case study BCAs is provided in Table VI below, where each jurisdiction's primary cost-effectiveness test (i.e., its JST) reflects the respective policy goals of the hypothetical jurisdiction, consistent with NSPM Principle 2. Other key NSPM principles applied to the case study BCAs 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);

[4] See NSPM for DERs Chapter 3 for additional discussion of traditional cost-effectiveness tests.

- 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).

> Importantly, a jurisdiction's BCA framework and primary JST applies to all cost-effectiveness assessments of DERs. This does not mean, however, that every JST impact is applicable to every DER and/or use case. Each case study in the report notes where an impact may be part of the jurisdiction's JST but is not applicable for the use case.

Table VI: Summary of Impacts Included in Case Studies

Category/Type	EV Managed Charging Case Study 1 (JST 1)	Solar + Storage Case Study (JST 2)	GEB Retrofit Case Study (JST 3)
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	All impacts included in JST though some values are zero where impact is not relevant to the use case and/or DER. GHG adder included*	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	Not applicable given jurisdiction's policies	Not applicable given jurisdiction's policies	Included in JST consistent with jurisdiction's policy
Host Customer Impacts	Not applicable given jurisdiction's policies	Included in JST consistent with jurisdiction's policy	Included in JST consistent with jurisdiction's policy
Societal Impacts	GHG emission impacts (beyond any compliance costs) included consistent with jurisdiction's policy	*No societal impacts included given jurisdiction's policies, *however,* GHG Adder included as utility system impact *in addition to* existing compliance costs	GHG emission impacts (beyond any compliance costs) and public health impacts included consistent with jurisdiction's policy

Consistent with NSPM Principle 7, to provide transparency in BCA practice, each 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 NSPM companion resource – *Methods, Tools and Resources Handbook for Quantifying DER Impacts for BCA* (referred throughout this document as the "MTR Handbook") — where additional information can be found on methods for monetizing impacts, including those that are hard to quantify.

Finally, consistent with NSPM Principle 8, these case studies do not address bill and rate impacts. While 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. As such, these case studies do not address rate and bill impact analyses.

1. Residential EV Managed Charging in the Midwest

This case study applies the NSPM for DERs principles and guidance to a BCA for a hypothetical residential EV managed charging program in the Midwest. The case study serves as an illustrative example to inform and guide BCA for residential EV managed charging programs.

1.1 Introduction

> Managed charging is defined here as incentivizing or otherwise influencing when electric vehicle charging takes place on an electric grid

The number of EVs in the United States is projected to grow by at least 7 and up to 23 times over the next decade.[5] The associated vehicle charging demand will increase loads on the nation's electric grid. For this reason, the availability of EV charging programs, including TOU rates and incentive programs, is growing. Examples of recently implemented EV charging programs include Pacific Gas & Electric's (PG&E) BMW iChargeForward program, National Grid's ConnectedSolutions program, San Diego Gas & Electric's Power Your Drive program, and Puget Sound's Up & Go Electric Residential & Off-Peak Charging Program.[6]

As these new programs and offerings have emerged, challenges with analyzing their benefits and costs have also surfaced. Common challenges that this case study aims to address include estimating changes to electrified load shapes and making informed assumptions about current and future EV charging methods.

1.2 Case Study Context and Assumptions

This case evaluates the cost-effectiveness of a hypothetical EV managed charging program proposed by an IOU in the Midwest. It evaluates the incremental impact of a customer with an EV switching from a flat rate to a TOU rate. It is assumed that the TOU rate is a special rate offered only to EV customers, and that customers are enrolled in the rate as part of a package offered by the utility which includes an incentive discounting an EV charger. 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 EV owners/operators pay full price for a Level II charger, charge their EV(s) when they desire at home and are charged a flat $/kWh rate.
DER Case	Residential EV owners/operators receive a utility rebate for their Level II charger if they switch to a TOU electric rate.

[5] Brattle. (2020). *Getting to 20 Million EVs by 2030 Opportunities for the Electricity Industry in Preparing for an EV Future.* https://www.brattle.com/wp-content/uploads/2021/05/19421_brattle_-_opportunities_for_the_electricity_industry_in_ev_transition_-_final.pdf

[6] SEPA. (2021). *The State of Managed Charging in 2021.*https://sepapower.org/resource/the-state-of-managed-charging-in-2021/

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

The IOU planning to offer the EV charging program is located in the Midwest and is connected to the Midcontinent Independent System Operator (MISO). The hypothetical generation mix for the region includes coal-fired power plants contributing a significant portion to baseload with marginal natural gas peaker plants operating when needed. Relative to other areas of the country, the region is assumed to have low avoided energy and capacity costs.

The jurisdiction in which the IOU is located and regulated has various applicable energy policy goals articulated in statute, regulatory decisions, or otherwise that set forth the purpose for utility investments related to DERs, specifically:

- Providing safe, reliable and reasonably priced electricity services; and
- Reducing greenhouse gas (GHG) emissions based on recently passed statute, which requires that regulatory policy include the societal impact of GHG emissions cost-effectiveness testing for DERs.[7]

A summary of the impacts accounted for in this case study BCA is provided in Table 1.1.

Table 1.1: Summary of Impacts Included in EV Managed Charging Case Study

Category/Type	EV Managed Charging Case Study (JST 1)
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	Not applicable given jurisdiction's policies
Host Customer Impacts	Not applicable given jurisdiction's policies
Societal Impacts	GHG emission impacts (beyond any compliance costs) included consistent with jurisdiction's policy

The applicable energy policy goals inform the "regulator's perspective" and the impacts included in this jurisdiction's primary cost-effectiveness test (i.e., its JST).

[7] Examples of jurisdictions with GHG emission reduction statues is provided at https://www.ncsl.org/research/energy/greenhouse-gas-emissions-reduction-targets-and-market-based-policies.aspx

In this DER case, the JST includes all electric utility system impacts and the societal impact due to changes in GHG emissions. No host customer impacts are included in the JST consistent with the policies of the jurisdiction that does not account for these impacts in its primary test.[8]

1.2.2 Reference Case & Proposed Program Details

This case study assumes the following for its reference case and the DER case (managed charging program), with further detail provided in Table 1.2:

- Reference case: Current residential EV owners/operators within the IOU's operating territory charge their EV(s) when they desire and are charged a flat $/kWh rate.
  - Most residential EV owners/users charge their vehicles at home using a level II charger and pay full price for their charger (assumed to be $1,000).
- Under the proposed DER case, an EV owner/operator would switch to a TOU electric rate in order to receive a utility incentive that discounts the cost of a level II EV charger (at about 50% or $500).
- The TOU rate is a two (2) period rate with a 3.5x cost differential between peak and off-peak prices.
- The measure life (charger lifespan) is assumed to be 11 years, while the program offering is assumed to run for 3 years (2022 - 2024).

All assumptions used in this case study, summarized in Table 1.2 below, are treated symmetrically in terms of ensuring that both benefits and costs are accounted for (NSPM Principle 3). In addition, the BCA considers future, long-term, and incremental costs (consistent with NSPM Principle 5).

Table 1.2: Summary of Case Study Context and Key Assumptions

Assumption Category	Assumption Description	Value/Assumption
Utility & Grid Profile	Program Administrator	An IOU
	Location	Midwest/MISO
	Regional Generation Mix	Significant presence of coal-fired power plants for baseload and marginal natural gas peaker plants
	Regional Utility Costs	Low avoided energy and capacity costs. System peak is during the day; evening generation is cheaper than daytime

[8] Unlike a traditional Utility Cost Test (UCT), this JST includes a societal impact (GHG emission benefits to society) which is not a utility-perspective impact stream. Likewise, the JST for this scenario does not align with a traditional Total Resource Cost (TRC) test, which takes utility and host customer impacts into account, whereas this jurisdiction's policy does not require inclusion of host customer impacts in its primary test. Thus, the JST in this case study is unique to the jurisdiction and in alignment with its applicable policies.

Assumption Category	Assumption Description	Value/Assumption
Policy Context	Key Policy/Regulatory Objectives	Regulatory priorities are to ensure safe, reliable and reasonably priced electricity (utility system impacts) and reducing GHG emissions
Reference Case	Current Assumed Residential EV Charging Behavior	Level II charger where customer pays full price and customer charges EV whenever they desire, and has no preference for when an EV is charged so long as it has a full charge the next morning
	Current EV Charging Rate	A flat $/kWh charge no matter the time-of-use
DER Case (Proposed Program Details)	Program Offering	Level II EV charger is discounted by 50% if the customer enrolls in a TOU rate
	Program Customer Type	Residential
	Program Offering Time Period/Length	3 years
	Average Retention for TOU rate customer	11 years
	Measure Life	11 years for an EV charger
	Number of NEW Participants Each Year	Year 1: 500 Year 2: 700 Year 3: 1,000
	Financial Incentive for Participants	$500/Installed Level II charger
	Program Administrator Cost	Assumed to equal 20% of financial incentives
	Discount Rate	Assumes a discount rate of 3%

1.3 Impacts Analyzed and Data Approach

Based on this jurisdiction's JST, and the description of the reference case and use case for the EV managed charging program, the Tables 1.3 and 1.4 below indicate:

- Which utility and non-utility system impacts are accounted for in the BCA;
- Where/how the DER operating profiles were estimated; and
- The associated data sources and approach used to quantify the impacts.[9]

[9] For more information about conducting BCAs for demand response and electrification technologies, please see the NSPM for DERs Chapter 7 and 10, respectively. For more information on methods to quantify impacts see MTR Handbook.

Tables 1.3 and 1.4 present the BCA input assumptions including data inputs, descriptions, and general methodology used. Note that 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 1.3: Electric Utility System Impacts

Type	Specific Impact	Data Description & Rationale
Generation	Energy Generation	Calculated using hourly (8760) avoided energy data from a Midwest utility. 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. This avoided cost data from the utility was generated during their IRP process and reflects the anticipated generation sources over the forecasted 20 years.
	Capacity	Calculated using avoided generation capacity price data from a Midwest utility. The avoided capacity price is an output of the utility IRP process and reflects anticipated short- and long-term capacity needs.
	Environmental Compliance	Environmental compliance costs (e.g., coal plant emissions) were accounted for within avoided energy costs. Ideally, these costs would be distinctly reported for transparency purposes, however since assumptions are based on actual utility data, a separate value was not available. In the case of GHG compliance costs, the value is zero because the utility has not incorporated GHG emission goals into their resource planning. GHG is treated instead as a societal impact.
	RPS/CES Compliance	While the jurisdiction has an RPS, and therefore this impact is part of its JST, the value is N/A in this use case because the load shapes assumed that energy consumption was not increased or decreased, only shifted. Therefore, RPS compliance is not impacted under the assumption that renewables are not being curtailed since the total energy consumed by the customer (and therefore produced by the utility) doesn't change.
	Market Price Effects	Market price impacts are from the Synapse Avoided Energy Supply Components in New England: 2021 Report and were adapted to the MISO market.[10] The $/kWh value of the market price impacts were proportionally scaled to reflect lower avoided costs of MISO in comparison to ISO-NE.
	Ancillary Services	California Avoided Cost Calculator 2020 data was used assuming ancillary services of 0.9% of avoided energy costs, which applied to the hourly avoided energy costs to quantify ancillary services benefits.
Transmission	Capacity	Calculated using avoided transmission capacity prices ($/peak kW) from a Midwest utility. Avoided transmission prices were generated from a standalone study analyzing the impacts of load reductions on T&D planning needs.
	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.

[10] Source: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

Type	Specific Impact	Data Description & Rationale
Distribution	Capacity	Calculated using avoided distribution capacity prices ($/peak kW) from a Midwest utility. Avoided distribution prices were generated from a standalone study analyzing the impacts of load reductions on T&D planning needs.
	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.[11]
	O&M	The avoided distribution $/kW value utilized is assumed to cover all distribution spending that can be avoided based on generalized peak kW reductions. As this DER use case doesn't consider a specific distribution feeder/circuit such as is done with an NWA, there are no additional incremental O&M or voltage benefits that can be quantified.
	Voltage	The avoided distribution $/kW value utilized is assumed to cover all distribution spending that can be avoided based on generalized peak kW reductions. As this DER use case doesn't consider a specific distribution feeder/circuit such as is done with an NWA, there are no additional incremental O&M or voltage benefits that can be quantified.
General	Financial Incentives	The assumed incentive level was estimated based on EV industry analysis and a literature survey of EV charger incentives.
	Program Administration Costs	The assumed level of program administration costs was estimated based on benchmarking historic costs for EV programs and EV industry analysis.
	Utility Performance Incentives	Not part of the JST for this jurisdiction since there are no utility performance incentives.
	Credit and Collection Costs	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't affect these costs.
	Risk	To quantify the value from risk reduction, a percent adder method was utilized. This was due to the lack of any jurisdiction numbers for the Midwest quantifying risk reductions per kWh or peak kW. A 5% adder for risk was utilized based on a literature review of risk adders for different jurisdictions. The key sources for the 5% adder were Energy Trust of Oregon and DC Sustainable Energy Utility.[12]
	Reliability	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't reduce utility expenditures on reliability.
	Resilience	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't have a material impact on utility system resilience.

[11] This analysis makes the common simplification of not dealing with time differentiated loss rates, other than utilizing a different average marginal loss rate for peak demand versus average energy consumption. Since marginal loss rates increase with higher loading, in reality loss rates are continually changing throughout the day. Therefore, shifting consumption to times of lower loading will result in decreased system losses. For the purposes of this use case, the value of those additional losses is assumed to be minor in comparison to the other benefits streams, and so is not calculated.

[12] 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

Table 1.4: Societal Impacts

Specific Impact	Data Description & Rationale
Resilience	Not included in the JST as not reflected in jurisdiction's applicable policies.
GHG Emissions	Calculated using the Midwest region assumptions from the EPA AVERT Tool to generate hourly emissions factors. This data was then combined with the U.S. EPA social cost of carbon (SCC) values (assuming a 3% discount rate) to generate the hourly $/kWh factors for valuing GHG emissions.[13] The DER use case assumes that the utility has not internalized the marginal abatement cost of carbon. It was conservatively assumed that the resource mix of the jurisdiction did not change over the course of the measure lives.[14]
Other Environmental Impacts	Not included in the JST as not reflected in jurisdiction's applicable policies.
Public Health	Not included in the JST as not reflected in jurisdiction's applicable policies.
Economic Development and Jobs	Not included in the JST as not reflected in jurisdiction's applicable policies.
Energy Security	Not included in the JST as not reflected in jurisdiction's applicable policies.

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

Accounting for GHG Emissions: Determining Utility System or Societal Impact - 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 tests[15]:

- 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.

[13] Sources: EPA AVERT Tool: https://www.epa.gov/avert; EPA social cost of carbon (SCC) values: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html#:~:text=Estimating%20the%20Benefits%20of%20Reducing%20Greenhouse%20Gas%20Emissions,%20%20%243%2C700%20%205%20more%20rows%20

[14] The EPA AVERT Tool was utilized for short-run marginal emissions rates due to the assumption that the DER would not impact long-term baseload generation planning. However, if the underlying assumption is that the resource will be significant enough to influence baseload generation planning, then long-run marginal emissions rates should be used. National Renewable Energy Laboratory (NREL)'s Cambium tool is one reliable source of long-run marginal emissions rates. See the GEB case study for additional discussion on utilizing the NREL Cambium tool.

[15] See MTR Handbook - Chapter 3.2.6 and Chapter 7.1.

This hypothetical jurisdiction assumes a Midwestern location which has high-level policy goals of decarbonization, but those goals have not yet been reflected in the utility's resource planning and therefore are not inherently accounted for in the utility's avoided energy cost. This, in combination with the assumed absence of a cap-and-trade carbon market, results in no incremental utility system avoided environmental compliance costs for carbon. Therefore, the high-level policy goal of decarbonizing is valued using a damage cost method as a societal impact and utilizes a social cost of carbon (SCC) for valuation (see Table 1.4 for data description).

Line Losses – In this case study, line loss savings are included in avoided T&D costs. Likewise, increased reliability benefits are included in avoided T&D and avoided generation costs. For this reason, line loss savings and reliability benefits are not shown as separate impact streams. This approach adheres to NSPM Principle 6 to avoid double counting impacts (see Table I). Depending on the data sources and methodologies used, other BCAs may need to account for reliability and/or line loss impacts separately.

Reliability – Reliability metrics (such as SAIDI, SAIFI, or CAIDI[16]) are typically used to inform a utility's annual reliability performance and expenditures. However, in this use case, the managed charging program would not improve these utility metrics. The ability of the managed charged program to help maintain a reliable grid is already captured by avoiding the T&D capacity investments that would have been required if the load shifting had not occurred.

Risk Benefits - Risk benefits are estimated to equal 5% of avoided energy costs and demand reduction induced price effects (DRIPE) benefits. Given that DRIPE has an elasticity function where the price suppression varies with both demand and commodity prices, there is exposure to volatility that this program offering can help mitigate. Likewise, energy costs can be subject to stochastic fuel price volatility.

Program Financial Incentives Costs - Lastly, program financial incentive costs are estimated based on program offerings and the expected number of new program participants each year, and program administration costs are assumed to equal 20% of total program financial incentives.

1.4 BCA Results

1.4.1 Summary of Inputs & Calculated Values

As outlined in Tables 1.3 and 1.4 above, a range of impact streams were used to calculate the net benefits of the proposed EV managed charging program, with the input variables summarized below and BCA results provided in Table 1.5.

[16] SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index). For more information on these reliability metrics, see MTR Handbook.

Summary of Relevant Value Streams for EV Managed Charging Case Study*	
Electric Utility System Impacts	Societal Impacts
• Avoided Energy Costs • Avoided Generation Capacity Costs • Avoided Transmission & Distribution Costs • Wholesale Price Benefits (DRIPE) • Risk Benefits • Avoided Ancillary Service Costs • Financial Incentive Costs • Program Administration Costs	• Greenhouse Gas Emission Impacts

*As noted in Table 1.3, some utility system impacts that are part of the jurisdictions primary JST are not included in the BCA for this use case because either the impact is not relevant to the use case or is immaterial in impact.

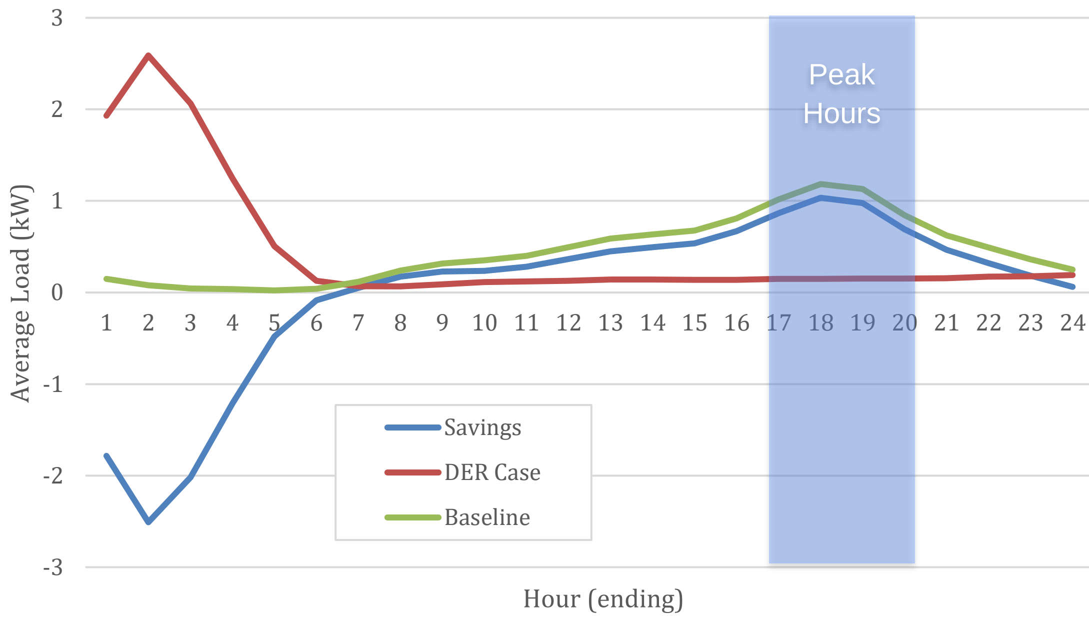
The selection and calculation of these impact streams was carefully reviewed to align with NSPM principles to ensure symmetry and to account for relevant, material impacts.

Load Shape Analysis & Impact Values

Calculating the values for many of these impact streams requires estimating the changes in kWh load per participant per hour of year. This is accomplished by subtracting the expected TOU-influenced charging load shape from the baseline load shape. EV charging load shapes were created using the light-duty vehicle data for Michigan from the medium electrification case of the NREL Electrification Futures Study (EFS) and expert judgement by ICF. The baseline load shape was assumed to be the 2024 light duty EV load shape from the NREL EFS's medium case. This load shape makes assumptions about the proportion of battery electric vehicles (BEV) to plug-in hybrid electric vehicles (PHEV) and vehicle miles driven per year.

The load shape for program participants assumed that EV customers are responsive to the TOU rate, that over 80% of enrolled EV charging load is shifted to off-peak times, and that there is no impact on the total amount of energy consumed (i.e., load is only shifted not decreased or increased). As illustrated in Figure A, this results in approximately 1kW of load shifting per customer. This is expected to be a conservative load shift estimate since the TOU rate is expected to be applied to the whole home, not just the EV charger.

Figure A: EV Managed Charging Load Shape Analysis: Baseline and DER Case



The changes in load shape are then used to calculate various impacts:

1. Avoided energy costs, using hourly generation cost data ($/kWh) from a Midwest utility:

$$Annual\ Avoided\ Energy\ Costs\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load\ _i * Hourly\ Generation\ Costs\ _i)$$

2. Wholesale price benefits, using hourly DRIPE values from the [2021 New England Avoided Energy Supply Components (AESC) study]adjusted for MISO:

$$Annual\ Wholesale\ Price\ Benefits\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load\ _i * Hourly\ DRIPE\ _i)$$

3. Avoided ancillary services costs (assumed to be 0.9% of avoided energy costs):

$$Avoided\ Ancillary\ Services\ Costs\ (\$) = Avoided\ Energy\ Costs * 0.009$$

4. Changes in GHG emissions, using U.S. EPA's AVERT tool and estimated SCC:

$$GHG\ Impacts\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load\ _i * GHG\ Emissions\ Rate\ _i * Social\ Cost\ of\ Carbon)$$

Changes in demand are also averaged across all annual system peak hours to determine an average annual peak reduction value (kW). This value is then used to determine avoided transmission and distribution costs and avoided generation capacity costs using real avoided costs from a Midwest utility. In this case study, the average annual peak reduction value is 1kW from on-peak to off-peak per customer.

Discount Rate

In order to calculate the net present value (NPV) of the future streams of benefits and costs of the program, a real discount rate of 3% was selected to reflect the "regulatory" time preference. Since a discount rate of 3% is one of the discrete rates for published SCC values, this case study was able to easily align the GHG value stream with the study-wide discount rate.[17]

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

Table 1.5: EV Managed Charging JST: BCA Values and Results

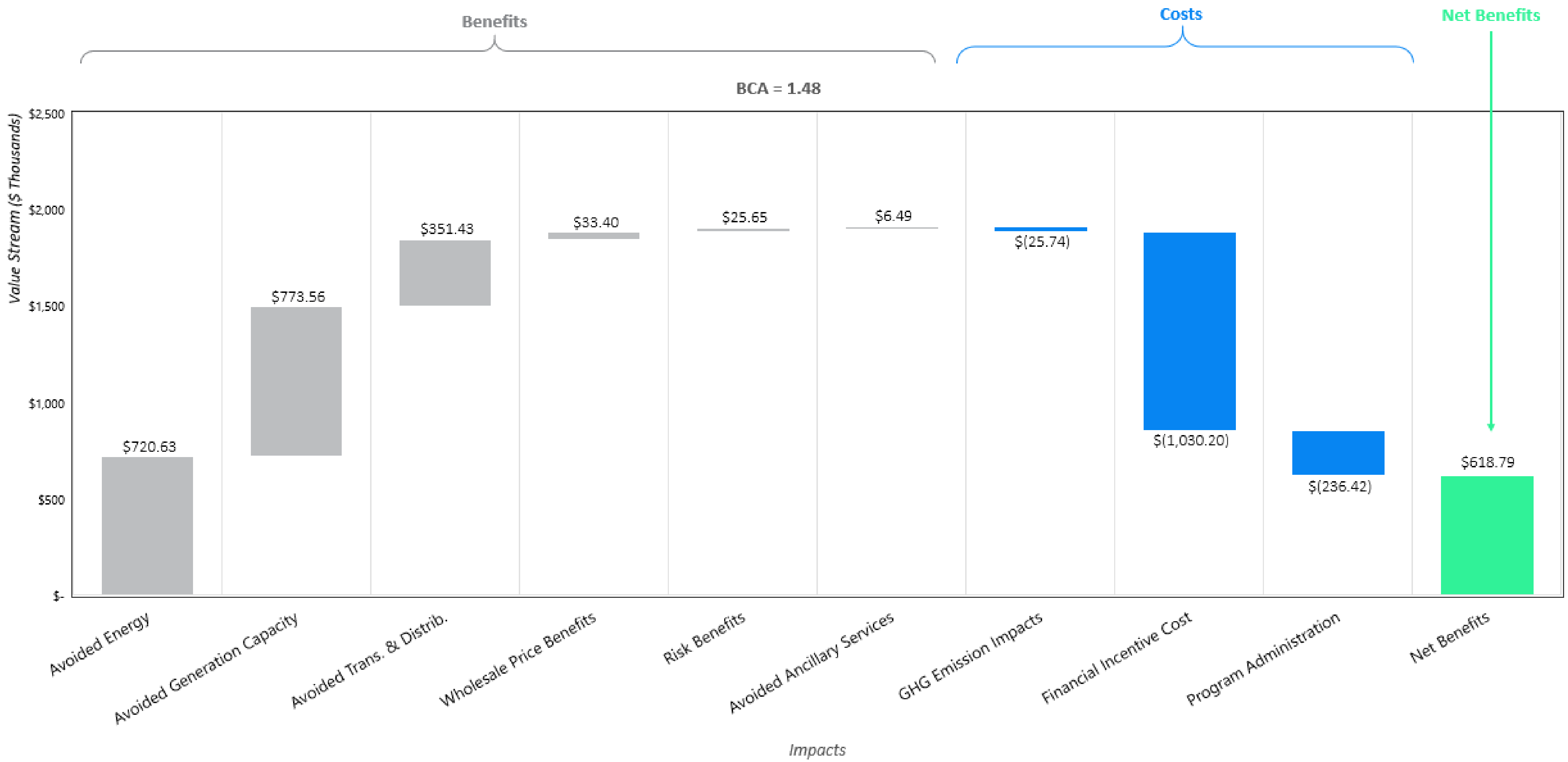
Value Stream	Net Present Value ($ 2021)
UTILITY SYSTEM IMPACTS	
Avoided Energy Costs	$ 720,634
Avoided Generation Capacity Costs	$ 773,558
Avoided Transmission & Distribution Costs	$ 351,426
Wholesale Price Benefits (DRIPE)	$ 33,399
Risk Benefits	$ 25,650
Avoided Ancillary Service Costs	$ 6,485
Financial Incentive Costs	$ (1,030,197)
Program Administration Costs	$ (236,417)
SOCIETAL IMPACT	
Greenhouse Gas Emission Impacts	$ (25,743)
Total Benefits	**$ 1,911,152**
Total Costs	**$ (1,292,357)**
Net Benefit	**$618,795**
Benefit-Cost Ratio	**1.48**

The benefit-cost ratio of this program is 1.48, with net benefits of $618,795. With a benefit-cost ratio greater than 1.0, the proposed program is cost-effective.

Figure B illustrates the BCA results for the EV Managed Charging JST.

[17] When this is not the case, the GHG value stream inputs should be interpolated or extrapolated based on the discreate values published to align this value stream. For more information on using an appropriate discount rate, see Chapters 5-11 and Appendix G of the NSPM for DERs.

Figure B: EV Managed Charging JST: Benefit-Cost Value Streams and Net Benefits



Key: Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

1.4.2 Summary of Case Study Key Factors and Findings

The key value streams which drove the BCA results are avoided energy costs, avoided generation capacity costs, and program financial incentive costs:

Utility System Impacts

- *Avoided energy costs*: The avoided energy costs are largely driven by a cost differential of 40 - 50% between peak and off-peak kWh generation (average on-peak costs are 6-7¢/kWh while off-peak are 3-4¢/kWh), and the significant average shift of 1kW from on-peak to off-peak per participant.
- *Avoided generation capacity costs*: Avoided generation capacity costs are the result of a $30/kW avoided generation capacity estimate.
- *Program financial incentive costs*: The $500 incentive value assumed in the case study is approximately 50% of the cost of a level II home charger with time flex capabilities, but it was chosen without other supplemental data such as pilot program participation results. Other program administrators may choose to offer larger or smaller incentives for program participation.

Overall, the JST's moderate benefit-cost ratio (1.48) is driven by avoided energy costs, including a significant cost differential between peak and off-peak kWh generation and a significant average shift from on-peak to off-peak per participant. Depending on load shapes and generation mixes, other regions of the country may have larger or smaller peak-to-off-peak cost differentials. Additionally, the JST's benefit-cost ratio is driven by avoided generation capacity costs. Depending on existing customer charging habits and system peak hours, other managed charging programs may predict smaller participant kW shifts. As utilities, regulators, and customers increasingly focus on managed charging for EVs, it is critical to evaluate the key impact streams that reflect the resource being analyzed.

Societal Impacts: GHG Emissions

The BCA shows a slight increase in GHG emissions as a result of the shift from on-peak daytime charging to off-peak nighttime charging. The marginal emissions rates of natural gas peaker plants are lower during the day than more carbon-intensive overnight resources (i.e., coal plants), resulting in the shift from peak charging to off-peak charging increasing GHG emissions slightly.

Additionally, the case study conservatively assumed that the resource mix of the hypothetical jurisdiction would not change over the course of the managed charging program. While a utility could spend the resources to model a shift towards a cleaner generation mix overtime, the GHG value stream is already very minor compared to other value streams and modeling a cleaner grid forecast would have only further diminished its relative scale.[18] Therefore, expending

[18] This is because the level of precision achieved for each value stream should ideally be proportional to the absolute value of the stream and should be reflective of the uncertainty found within a value stream's inputs.

additional cost to calculate the value of GHG emission changes more precisely would not have changed the overall BCA result. However, if policies were in place that prohibited increases in GHG emissions or placed a large price on GHG emissions, then this impact stream could become more influential in the BCA. Likewise, if the jurisdiction chose to use a lower discount rate (a 3% real discount rate was used), then the GHG impact stream would have been larger.

1.4.3 Conclusions and Areas for Further Research

This case study demonstrates two key concepts that are important to BCA analysis. The first is that the granularity of the savings estimates used should reflect the resource being analyzed. In this case, utilizing hourly avoided cost data allowed for an accurate estimation of the value of load shifting. This resulted in avoided energy benefits that were nearly equal to avoided generation capacity benefits, the value stream that is often considered the focal point of programs that are designed to avoid peak loading.

Secondly, this case study provides a concrete example of a meaningful BCA mantra, that the effort expended in quantifying a value stream should be proportional to the impact and uncertainty of that value stream. This is consistent with NSPM guidance which sets forth that any impact that is deemed to be relevant to a jurisdiction's policies should be included as part of the definition of its primary JST, however in some cases, a benefit or cost may be relevant but not material.[19] Impacts determined to be immaterial should be documented, but not necessarily included in the BCA so as to avoid expending study costs that have de minimus impact on the BCA results and can be highly inaccurate.

One area for further research is the response of different customer types to different load shifting strategies for EVs, and in general the use of more evidence-based approaches in quantifying the hourly impacts of DERs. As more and more different DR and flexible load management approaches emerge, it is vital to be able to have confidence in the estimated load impacts so the value of these programs can be accurately assessed.

[19] *Material* impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA.

2. Commercial Solar + Storage Controlled Dispatch in the West

This case study applies the NSPM for DERs principles and guidance to a BCA for a hypothetical commercial solar and storage (solar + storage) program in the Western U.S. region. This case study can be used as an illustrative example to inform and guide BCA approaches to commercial BTM solar + storage programs.

2.1 Introduction

As U.S. regulators and utilities focus on addressing evolving concerns over grid reliability and flexibility, paired BTM solar + storage applications continue to gain traction. According to Lawrence Berkeley National Laboratory's *Behind-the-Meter Solar + Storage: Market data and trends* (2021) report, BTM battery storage represented approximately 30% of U.S. battery capacity installed through 2020 (approximately 1,000 MW); with 550 MW paired with solar.[20] For non-residential[21] battery storage installations through 2020, approximately 40% were paired with solar (versus residential BTM energy storage's rate of approximately 80%).[22] Additionally, within the non-residential sector, for-profit commercial entities make up the majority of all paired solar + storage installations, at 70%.[23] Key drivers for providing commercial solar + storage programs often include customer cost savings and other grid services such as demand management and reliability, with an increasing focus on environmental impacts.

As these new programs and offerings have emerged, challenges with analyzing their benefits and costs and determining cost-effectiveness have also surfaced. Common challenges that this case study aims to address include comprehensively addressing the full range of program benefits and costs, including utility system and host customer impacts such as avoided generation capacity, federal and state incentives, depreciation, and host customer reliability.

2.2 Case Study Context and Assumptions

This case study evaluates the cost-effectiveness of a hypothetical commercial BTM solar + storage program to be provided by an IOU in the Western U.S. region. It evaluates the incremental impact of an incentive-driven program for small commercial customers that install rooftop solar PV paired with a BESS. The objective of the BCA is to determine the incremental value of BESS and help determine if the quantified benefits of the proposed program outweigh

[20] Source: Barbose, G., Elmallah, S., and Gorman, W. (2021). *Behind-the-Meter Solar+ Storage: Market data and trends*. Lawrence Berkeley National Laboratory., 6. https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf

LBNL's *Behind-the-Meter Solar+ Storage: Market data and trends* report relies primarily on Berkeley Lab's Tracking the Sun dataset.

[21] Non-residential category includes commercial, non-profit, gov't, and schools.

[22] Barbose et al. (2021). *Behind-the-Meter Solar+ Storage: Market data and trends*., 6, 12.

[23] Barbose et al. (2021). *Behind-the-Meter Solar+ Storage: Market data and trends*., 11.

the proposed costs, using a JST described below. Two secondary tests are also presented to further inform regulatory decision-making and provide additional information.

Reference Case	Small commercial customers install stand-alone rooftop solar PV, customer is on TOU rate.
DER Case	Small commercial customers receive a state government and utility incentive to install a BESS, so customers decide to install the BESS in combination with a rooftop PV system, customer is on TOU rate.

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

The case study assumes that the IOU offering the BTM solar + storage program is located in the Western U.S. region and does not have a Regional Transmission Operator (RTO). The hypothetical generation mix for the region includes significant renewable energy resources, including BTM solar PV. The hypothetical utility is assumed to be pursuing carbon reduction strategies to align with state polices, as detailed below. Relative to other areas of the country, the region is assumed to have high avoided capacity costs.

The jurisdiction in which the IOU is located and regulated has various applicable energy policy goals articulated in statute, regulatory decisions, or otherwise that set forth the purpose for utility investments related to DERs, such as incentives to encourage BTM energy storage with solar. In this hypothetical jurisdiction, beyond the overarching goals of providing safe, reliable, and reasonably priced electricity and gas services, the jurisdiction also has goals to:

- Improve system reliability and resilience;
- Reduce system risk;
- Reduce GHG emissions, based on recently passed statutes.[24] Specifically, the jurisdiction has set an aggressive state-level GHG emissions reductions target of being carbon neutral by 2050, with state goals for aggressive decarbonization (including for utilities) and carbon neutrality in the medium horizon. Additionally, the state participates in a carbon cap & trade program.
- Further, regulatory policy also requires including host customer impacts in cost-effectiveness testing for DERs.

These applicable energy policy goals inform the “regulator’s perspective” and the impacts accounted for in the jurisdiction’s primary cost-effectiveness test – its JST. In this solar + storage case study, the JST accounts for utility and host customer impacts. Gas utility system and other fuels impacts were not considered for this case study, as they were not relevant to the DER/use case. Societal impacts were not considered for this case study, as they were not reflected in the jurisdiction’s applicable policies and JST; however, the treatment of GHG emissions is fully accounted for as a utility system impact (versus also as a societal impact), which is further explained below and in section 2.3. [25]

[24] Examples of jurisdictions with GHG emission reduction statues is provided at https://www.ncsl.org/research/energy/greenhouse-gas-emissions-reduction-targets-and-market-based-policies.aspx
[25] Unlike a traditional Utility Cost Test (UCT) this JST includes host customer impacts which are not impact streams from a utility-perspective. In general, JSTs may or may not align with traditional cost-benefit tests depending on a

A summary of the impacts accounted for in this case study BCA is provided in Table 2.1.

Table 2.1: Summary of Impacts Included in Solar + Storage Case Study

Category/Type	Solar + Storage Case Study (JST 2)
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. GHG adder included*
Natural Gas Impacts	Not applicable given jurisdiction's policies
Host Customer Impacts	Included in JST consistent with jurisdiction's policy
Societal Impacts	*No societal impacts included given jurisdiction's policies, *however,* GHG Adder included as utility system impact *in addition to* existing compliance costs

2.2.2 Reference Case & Proposed Program Details

This case study assumes the following for its reference case and the DER case (solar + storage program), with further detail provided in Table 2.2:

- Reference case: Small commercial customers within the IOU's operating territory install stand-alone rooftop solar PV and are on a TOU electric rate.
- DER case: Small commercial customers receive a state-level and utility incentive to install a BESS, so the customers decide to install a BESS paired with the rooftop solar PV.
- The BESS can only charge from the solar PV system and cannot charge from the grid in order for the customer to claim the full ITC value for the BESS installation.
- The state incentive level for participants is $175 per kWh.
- The utility incentive level for participants is $75 per kWh.
- The measure life of the BESS is assumed to be 10 years, and the customer is assumed to stay on the TOU rate for the duration of the BESS' useful life.

jurisdiction's specific regulator perspective. It is often the case that jurisdictional policies do not necessarily articulate whether host customer benefits and costs should be accounted for in a primary cost-effectiveness test. The decision of which non-utility system impacts should be included in a JST, in order to reflect policy goals, will need to be made by regulators with appropriate input from stakeholders. For further discussion, see NSPM for DERs, Chapter 3.

Table 2.2: Summary of Case Study Context and Key Assumptions

Assumption Category	Assumption Description	Value/Assumption
Utility & Grid Profile	Program Administrator	An IOU
	Location	A Western state that does not have an RTO
	Regional Generation Mix / Grid Profile	● Significant renewable energy penetration, including solar PV ● Grid reliability constraints, e.g., public safety power shutoff (PSPS)
	Regional Utility Costs	High avoided capacity costs
Policy Context	Key policy/regulatory objectives	● State incentive program (in addition to the proposed program offering) to encourage DER deployment, including energy storage ● Aggressive state-level GHG emissions reductions targets with goal of being carbon neutral by 2050 ● Grid reliability concerns ● Regulatory policy requires including host customer impacts in cost-effectiveness tests
Reference Case	Baseline Program Assumptions	Small commercial customer installs a 20 kW rooftop solar array, and is on TOU rate
DER Case (Proposed Program Details)	Program Offering	Small commercial customer installs a 20 kW rooftop solar PV array paired with a 14 kW / 86 kWh[26] BESS, and is on a TOU rate; there is a utility and state incentive for BESS installation
	Financial Incentive for Participants	● The state incentive level for participants is $175 per kWh[27] ● The utility incentive level is $75 per kWh
	DER Operational Profile	BESS can only charge based on the solar PV system (cannot charge from the grid) to fulfill requirements to claim the full ITC value, and will discharge for peak TOU optimization

[26] For further information on understanding BESS sizing, see https://www.nrel.gov/state-local-tribal/blog/posts/batteries-101-series-how-to-talk-about-batteries-and-power-to-energy-ratios.html

[27] Based on the Self Generation Incentive Program (SGIP) in California, with customer receiving a $/kWh incentive from utility for installing storage onsite. Modeling assumed an incentive level of half of the SGIP. California's SGIP provides financial incentives for the installation of distributed generation and advanced energy storage technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by program administrators representing California's large IOUs. Sources: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program/participating-in-self-generation-incentive-program-sgip; and https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/6442463457-2019-sgip-energy-storage-market-assesssment-ce-report-2019.pdf

Assumption Category	Assumption Description	Value/Assumption
	Program Customer Type	Commercial (small office building) with regular daytime operations
	Rate Class	Small to medium Commercial & Industrial (C&I) TOU rate class[28]
	Program Offering Time Period/Length	3 years
	Contract Length for TOU rate	10 years
	Measure Life	10 years for BESS[29]
	Number of NEW Participants Each Year	Year 1: 50 Year 2: 70 Year 3: 100
	Discount Rate	Discount rate of 3.6% was used to reflect the regulator time preference being between the weighted average cost of capital (WACC) of 4.6% and the jurisdiction-specific societal discount rate of 2.5%[30]

2.3 Impacts Analyzed and Data Approach

Based on this jurisdiction's JST, and the description of the reference case and DER case (commercial solar + storage program), the Tables 2.3 and 2.4 below indicate:

- Which utility and non-utility system impacts are accounted for in the JST;
- Where/how the DER operating profiles were estimated; and
- The associated data sources and approach used to quantify the impacts.[31]

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.

[28] The TOU rate is based on PG&E's B1-ST Rate, with an average on-peak price of $0.40 /kWh and off-peak of $0.21/kWh. Source: https://www.pge.com/en_US/small-medium-business/save-energy-and-money/battery-storage/b1-st.page

[29] Based on NREL REopt modeling; 10 years is the default lifetime of the BESS before the system will need to be refurbished/replaced. Source: https://reopt.nrel.gov/

[30] The discount rate alignment between the utility's WACC and a societal discount rate was based on a regulatory time preference approach between a Utility Cost Test (UTC) and Societal Cost Test (SCT).

[31] For more information about conducting the BCA for DERs for distributed generation and distributed storage technologies please reference the NSPM for DERs Chapters 8 and 9, respectively. 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.

Table 2.3: Electric Utility System Impacts

Type	Specific Impact	Data Description & Rationale
Generation	Energy Generation	Calculated using the 2020 California Avoided Cost Calculator (2020 California ACC). This value is derived from the production cost modeling efforts for California as listed in CPUC. It is adjusted to only reflect the "energy-only" value.
	Capacity	Calculated using the 2020 California ACC. Net cost of new entry (CONE) of 4-hour battery storage in California Integrated System Operator (CAISO).
	Environmental Compliance (Avoided GHG Cap and Trade Compliance)	Value stream represents the avoided carbon cap-and-trade allowance costs, as derived from the 2020 California ACC. This is the short-term cost to utilities of purchasing carbon allowances, and in the 2020 California ACC only accounts for marginal emissions up to the annual grid intensity target.
	Environmental Compliance (GHG Rebalancing / Adder)	Based on GHG Adder[32] and GHG Rebalancing[33] value streams from the 2020 California ACC. The GHG Adder is defined as the non-monetized carbon price beyond the cost of cap-and-trade allowances. It is the price differential between the forecasted shadow price obtained from a long-term capacity expansion model and the state's cap-and-trade prices. GHG Rebalancing is defined as the rebalancing of emissions to meet annual electric grid GHG intensity targets from IRP. This step accounts for how the utility resource plan will adjust for added DER and be rebalanced to achieve the annual emissions intensity target.
	RPS/CES Compliance	While the jurisdiction has an RPS, and therefore this impact is part of its JST, no value is included in this use case because there is no incremental value stream considered for RPS/CES since the decarbonization legislation which is accounted for in the environmental compliance value stream results in renewable penetration exceeding the RPS. Incremental valuation would be double counting.
	Market Price Effects	Not part of the JST for this jurisdiction because the utility is assumed to not participate in an RTO/ISO.
	Ancillary Services	Calculated using the 2020 California ACC. The load-dependent aspect of ancillary services is accounted as a benefit. The historical 0.9% of the value is adjusted annually to reflect prices seen in production cost modeling.

[32] The 2020 California ACC includes a GHG adder, which is the difference between the GHG avoided cost and the cap-and-trade allowance price forecast. The 2020 California ACC includes separate categories for the cap-and-trade allowance price, the GHG Adder and, the GHG Rebalancing value stream which together represent the GHG avoided cost. Source: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K054/340054558.PDF

[33] The 2020 California ACC includes GHG rebalancing, which is an adjustment to account for the allowed minimal carbon emissions during the forecasted period. Source: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K054/340054558.PDF and https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

Type	Specific Impact	Data Description & Rationale
Transmission	Capacity	Calculated using the 2020 California ACC. Given the locational and temporal uncertainty, the transmission avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, this approach is considered appropriate relative to trying to forecast locational needs far into the future.
	System Losses	Transmission system losses were accounted for within avoided energy and capacity costs. In quantifying avoided energy, assumed a marginal loss rate of 12.21%, inclusive of T&D systems.
Distribution	Capacity	Calculated using the 2020 California ACC. Given the locational and temporal uncertainty, the distribution avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, this approach is considered appropriate relative to trying to forecast locational needs far into the future.
	System Losses	Distribution system losses were accounted for within avoided energy and capacity costs. In quantifying avoided energy, assumed a marginal loss rate of 12.21%, inclusive of T&D systems.
	O&M	Distribution spending decreases related to load impacts were accounted for in the 2020 California ACC value stream utilized for the Distribution Capacity benefits, therefore no incremental value was assumed for Distribution O&M as a separate category.[34]
	Voltage	While part of the JST for this jurisdiction, no value is included in the BCA because of the DER installation levels deployed and geographic dispersion; distribution voltage impacts were assumed to not be significant and so no value is included.[35]
General	Financial Incentives	The utility incentive has been included as part of the value streams for the JST since host customer impacts are included. See below for how this impacts the treatment of the host customer incremental capital cost. The state-level incentive is included as a distinct value stream since the perspective of the JST doesn't include societal impacts, and so the cost of the state tax incentive to non-host customers is not accounted for.
	Program Administration Costs	Assumed program administration costs are approximately 30% of total program costs (utility incentive + administration), which is reflective of cost ratios observed in industry for solar + storage program operation.
	Utility Performance Incentives	Not part of the JST for this jurisdiction because there are no utility performance incentives for any DER programs.

[34] Ideally distribution capacity and distribution O&M would be calculated as individual value streams, however, based on data availability these streams are often combined into a single impact.

[35] Distribution voltage impacts could be more significant if DER use case deployment was geographically concentrated, as impact is highly dependent on feeder profile/use and specific geographic location.

Type	Specific Impact	Data Description & Rationale
	Credit and Collection Costs	While part of the JST for this jurisdiction, no value is included for this impact because there are no credit and collection costs associated with this use case.
	Risk	To quantify the value from risk reduction, a percent adder method was utilized. A 5% adder for risk (avoided energy costs and avoided cap & trade costs) was utilized based on a literature review of risk adders for different jurisdictions. The key sources for the 5% adder were Energy Trust of Oregon and DC Sustainable Energy Utility.[36]
	Reliability	While part of the JST for this jurisdiction, no value is included for this impact because the DER doesn't reduce utility expenditures on reliability.[37] See host customer reliability impacts.
	Resilience	While part of the JST for this jurisdiction, no value is included for this use case because the DER doesn't have a meaningful impact on utility system resilience.

Table 2.4: Host Customer Impacts

Specific Impact	Data Description & Rationale
Host Portion of DER/Measure Costs	The BESS capital cost was calculated using a two-part approach based on BESS power and energy capacity as is common practice in industry. The $/kW capital cost are from Lazard 2020 stand-alone battery estimates, and $/kWh capital cost values for 2022 are from the California Public Utilities Commission, Inputs & Assumptions: 2019-2020 Integrated Resource Planning report.[38] O&M costs were also calculated based on EPRI estimates[39] and assumed 1.5% of capital costs for years 1-3 and 2.5% annually for the remaining BESS measure life. Since the utility incentive is included in the JST formulation, the net host customer incremental capital cost (total host customer capital incremental cost minus incentive) is included as a value stream in the JST.
Host Transaction Costs	While part of the JST for this jurisdiction, the value is considered zero because installing a BESS to a solar PV system is not anticipated to differ significantly from installing a stand-alone PV system.
Interconnection Fees	Interconnection cost is classified as a host customer cost since the cost to the utility to interconnect the DER is directly passed through to the host customer.

[36] 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

[37] Reliability metrics including SAIFI, CAIDI, and SAIDI inform a utility's annual reliability performance and expenditures. Source: https://www.pge.com/pge_global/common/pdfs/outages/planning-and-preparedness/safety-and-preparedness/grid-reliability/electric-reliability-reports/CPUC-2020-Annual-Electric-Reliability-Report.pdf

[38] Sources: https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf, and https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf

[39] Source: Fixed O&M costs are from Electric Power Research Institute (EPRI). (2018). *Energy Storage Technology and Cost Assessment: Executive Summary*, 15 (Lithium-Ion). https://www.epri.com/research/products/3002013958

Specific Impact	Data Description & Rationale
Risk	Since risks could potentially be both costs and benefits, depending on the performance of the battery over time, as well as hedging against rate increases, there is a high degree of uncertainty and potential for offsetting impacts. [40] Therefore, this value stream is assumed to be zero.
Reliability (Value of Lost Load)	The Value of Lost Load (VoLL) is sourced from the Synapse New England Avoided Energy Supply Components: 2021 report. The reliability metrics are sourced from PG&E's 2021 Reliability Report.[41] It is assumed that the economic VoLL for the C&I customers in the New England area will be comparable to the utility's customers in the West and hence have VoLL. The reliability metrics SAIFI, CAIDI, and SAIDI inform a utility's annual reliability performance. On the basis of total outages and the duration of the outage, outages that can be mitigated with an on-site BESS are quantified.
Resilience	While part of the JST for this jurisdiction, it is assumed that the DERs are installed in locations that are not high probability areas for long-term outages, and that resilience impacts for commercial offices are likely immaterial.
Tax Incentives & Depreciation	Included due to Federal Investment Tax Credit (ITC), state financial incentives, and depreciation tax write-off. The ITC was calculated as 26% of BESS system capital cost.[42] State financial incentives are realized based on California's Self-Generation Incentive Program (SGIP). While the SGIP incentive is $350/kWh[43] of BESS energy capacity, this case study assumed a more moderate incentive level of $175/kWh. For depreciation, the host customer is eligible to write off 21% of BESS system capital cost after subtracting 50% of the ITC.[44]

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

Interconnection Fees - In this case study, the interconnection fee charged to the host customer is counted as a host customer cost. The interconnection cost is classified as a host customer cost since the cost to the utility to interconnect the DER is directly passed through to the host customer. It is not appropriate to include in the utility system cost category since it doesn't impact revenue requirements for the utility. If it were the case that the utility bore the cost of the interconnection, then the interconnection costs would be a utility system cost. In addition, if for some reason the interconnection fee to the customer only covered a portion of the total interconnection cost to the utility, then the portion not covered by the fee would be a utility system cost

[40] See NSPM for DERs Chapter 9 for additional discussion of distributed storage benefits and costs.

[41] Source: https://www.pge.com/pge_global/common/pdfs/outages/planning-and-preparedness/safety-and-preparedness/grid-reliability/electric-reliability-reports/CPUC-2020-Annual-Electric-Reliability-Report.pdf

[42] Federal tax law applied as based on equations from NREL REopt. Source: NREL REopt Lite User Manual

[43] Source: Self-Generated Incentive Program (SGIP) non-residential (ca.gov)

[44] The Modified Accelerated Cost Recovery System (MACRS) is the current tax depreciation system in the United States, wherein the capitalized cost (basis) of tangible property is recovered over a specified life by annual deductions for depreciation. The benefit from the MACRS basis is reduced by 50% of the ITC Value. Federal tax law as understood by equations from NREL REopt pt.

Accounting for State Tax Incentives - State tax incentives are treated as a benefit to the host customers since the "regulatory perspective" in this case reflects a TRC-type perspective where both utility and host customer impacts are included. While this case study includes tax incentives as a host customer benefit, this treatment would differ in the case where the JST reflected a theoretical "societal" perspective. Using a societal perspective would imply that, since state taxpayers are included within the societal perspective, the tax incentive benefit to host customers would be entirely offset by the cost to state taxpayers. See NSPM Appendix F for additional guidance on treatment of offsetting payments.

Accounting for GHG Emissions - In this case study, GHG emissions are fully accounted for in the utility system impacts category as avoided environmental compliance costs plus a GHG Adder. This is due to the state's aggressive state-level GHG reductions targets (i.e., pursuing carbon-neutrality by 2050), with the assumption that the hypothetical utility has a comprehensive carbon reduction plan and is fully internalizing costs. As such, it is assumed that the policies in the hypothetical jurisdiction have put the utility on a path to full decarbonization in a timeframe that allows for minimal GHG damages. Therefore, the case study fully captures the cost of achieving the carbon reduction goals as a utility system impact, with no need to account for any GHG reductions as a societal impact. Instead, the costs have been internalized by the utility using the Marginal Abatement Cost (MAC) to the utility as reflective of the full value of GHG impacts from DERs (see Table 2.4 for data description). Note that based on the sources utilized, the MAC spans multiple value streams, including the GHG cap-and-trade compliance, GHG adder, and GHG rebalancing. For further discussion of treatment of GHG emissions, see the MTR Handbook.[45]

Accounting for Host Customer Reliability - Customer reliability was modeled using SAIFI and the VoLL for small C&I customers, which was calculated at $151 / kWh.[46] Customer reliability calculations analyzed the average building load and BESS state of charge.[47] A uniform distribution of outages was assumed, with an average 2-hour outage duration per customer and 4-hour hold-over time per customer.

2.4 BCA Results

2.4.1 Summary of Inputs & Calculated Values

As outlined in Table 2.3 and Table 2.4 above, a range of utility system impact and host customer impact streams were used to calculate the net benefits of the proposed solar + storage program, with the input variables summarized below and BCA results provided in Table 2.5.

[45] See MTR Handbook - Chapter 3.2.6 and Chapter 7.1.

[46] Source: Synapse 2021 Avoided Energy Supply Components for New England.

[47] A 10% threshold for the state of the battery charge was assumed.

*Summary of Relevant Value Streams for Solar + Storage Case Study**	
Electric Utility System Impacts	*Host Customer Impacts*
• Avoided Energy Costs • Avoided Generation Capacity Costs • Avoided Transmission Capacity Costs • Avoided Distribution Capacity Costs • Avoided Ancillary Services • Avoided Environmental Compliance – GHG Cap-and-Trade Compliance Costs • Avoided Environmental Compliance -GHG Adder / GHG Rebalancing costs • Utility Financial Incentive • Reduced Risk • Program Administration	• BESS Interconnection Costs • Increased Reliability • Federal ITC • State Financial Incentive • Depreciation Tax Write-off • Operations & Maintenance (O&M) Costs • BESS Net Capital Cost • Non-energy Impacts

*As noted in Tables 2.3 and 2.4, 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.

BESS Dispatch Load Shape Analysis

NREL REopt simulations were used to determine the load shape for the BESS. The case study assumed a small office as the prototypical building, with a max 20 kW[48] rooftop solar PV array size as the baseline. For the proposed program, the existing 20kW solar PV array was paired with a 14kW, 86 kWh BESS and TOU tariff.[49] The load shape utilized is the dispatch load shape of the BESS, which charges exclusively from the solar PV array, and discharges to maximize customer economics. The TOU tariff includes an average on-peak price of $0.40 /kWh and off-peak of $0.21 /kWh, with an estimated 6-7 kW of load reduction during peak times.

Discount Rate

A discount rate of 3.6% was used to reflect the regulator time preference being between the WACC of 4.6% and the jurisdiction-specific societal discount rate of 2.5%. 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).

[48] Based on 5,500 square feet of roof area, 50% of which is viable for solar, with 7.5 watts per square feet. NREL REopt calculated the 20kW solar PV array as economic.

[49] As optimally sized by NREL REopt simulations.

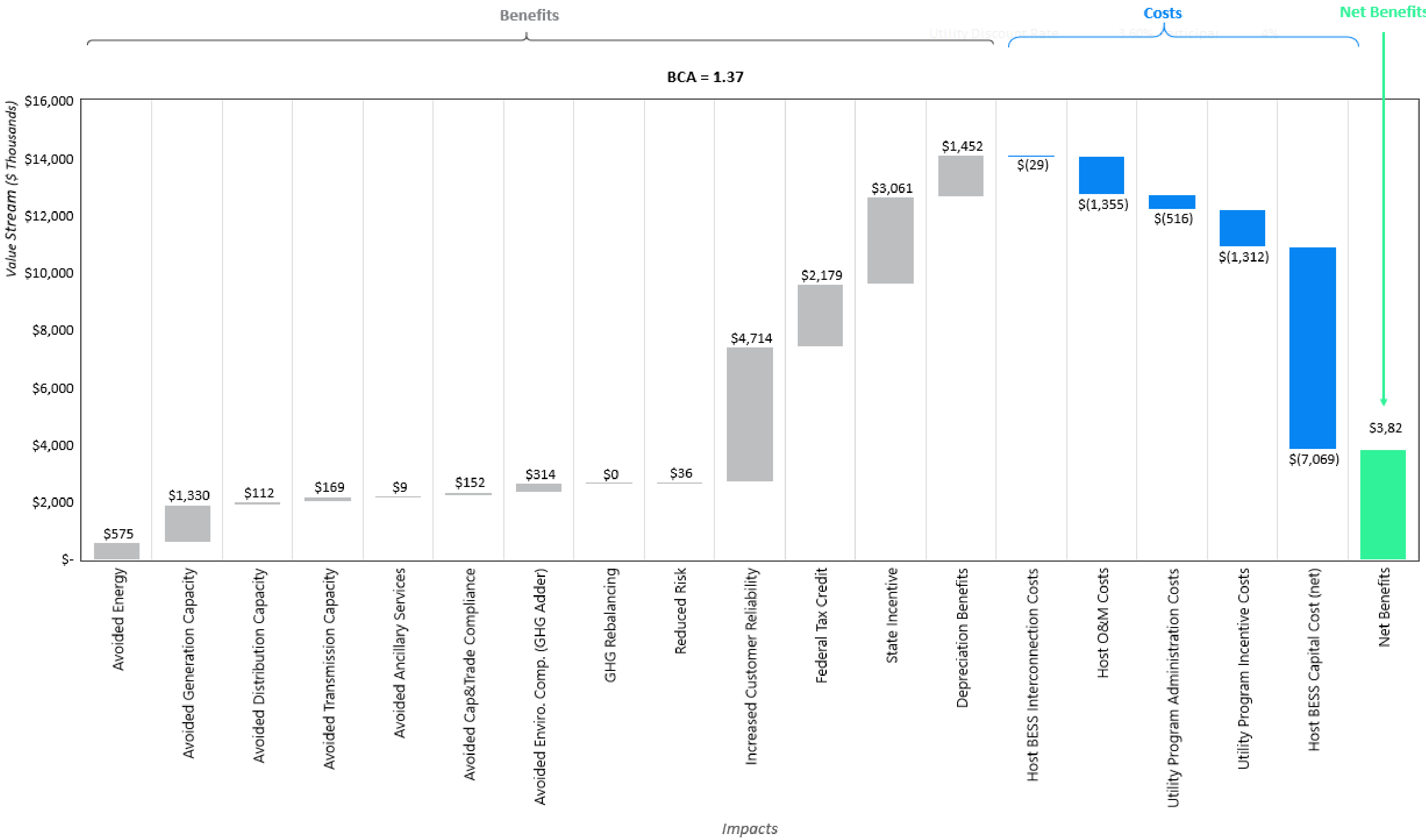
Table 2.5: Solar + Storage JST: BCA Values and Results

Value Stream	Net Present Value ($ 2021)
ELECTRIC UTILITY SYSTEM IMPACTS	
Avoided Energy	$ 574,605
Avoided Generation Capacity	$ 1,330,213
Avoided Distribution Capacity	$ 112,044
Avoided Transmission Capacity	$ 169,013
Avoided Ancillary Services (A/S)	$ 8,559
Avoided Cap & Trade Cost Compliance	$ 152,494
Avoided Environmental Compliance Costs – GHG Adder	$ 314,347
GHG Rebalancing	$ 75
Reduced Risk	$ 36,355
Utility Program Administration Costs	$ (515,969)
Utility Program Incentive Costs	$ (1,312,030)
HOST CUSTOMER IMPACTS	
Increased Customer Reliability	$ 4,713,688
Federal Tax Credit	$ 2,179,093
State Incentive	$ 3,061,404
Depreciation Benefits	$ 1,451,679
Host BESS Interconnection Costs	$ (29,495)
Host O&M Costs	$ (1,354,660)
Host BESS Capital Cost (net of incentives)	$ (7,069,097)
Total Benefits	**$ 14,103,569**
Total Costs	**$ (10,281,251)**
Net Benefits	**$3,822,318**
Benefit Cost Ratio	**1.37**

The benefit-cost ratio of this program is 1.37, with net benefits of $3,822,318. With a benefit-cost ratio greater than 1.0, the proposed program is cost-effective.

Figure C illustrates the BCA results for the Commercial Solar + Storage JST.

Figure C: Solar + Storage JST: Benefit-Cost Value Streams and Net Benefits



Key: Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

2.4.2 Summary of Case Study Key Factors and Findings

The key value streams which drove the BCA results for this case study are host customer reliability benefits, the value of state incentives, federal ITCs, depreciation tax write-offs, and avoided generation capacity and energy costs.

Host Customer Impacts

- *Host Customer Reliability Benefits:* The significant customer reliability benefits are driven by the pairing of the on-site BESS with the solar PV array, with the BESS providing economic value by mitigating outages as represented by the VoLL and the utility reliability metrics SAIFI, CAIDI, and SAIDI.
- *State & Federal Incentives and Depreciation:* Significant benefits also accrue due to the value of the state incentive, federal ITC, and depreciation. The value of incentives is clearly illustrated, with 36% of upfront BESS costs covered by the state incentive program and an additional 16% covered by a utility-specific incentive program. On top of these streams, the federal ITC covers 26% of the capital costs, and depreciation benefits cover another 17%, so that together all of these streams over approximately 95% of the total upfront costs of the BESS.

Utility System Impacts

- *Avoided Generation Capacity*: The avoided generation capacity benefits are largely driven by a high $/kW in the near term of $106/kW, due to the paired solar + storage program shifting utility system peak and reducing generation capacity requirements.
- *Avoided Energy Costs*: The avoided energy costs are largely driven by the BESS discharging to maximize customer economics via the TOU tariff, with an estimated 6-7 kW of load reduction during peak times (with an average on-peak price of $0.40 /kWh and off-peak of $0.21 /kWh).

Overall, the JST's moderate benefit-cost ratio (1.37) is driven by a high state-level incentive; however, even if the state-level incentive was significantly reduced or phased out, the program would still have a benefit-cost ratio above 1.0 and be considered cost-effective due to a significant contribution from customer reliability benefits. As utilities, regulators, and customers increasingly focus on grid reliability in response to extreme weather events, increased customer reliability can be a key impact stream to evaluate and include in BCA, assuming alignment with jurisdictional objectives and priorities.

2.5 Use of Secondary Tests

In addition to the primary JST, two secondary cost-effectiveness tests were conducted for this case study: a Utility Cost Test/Program Administrator Cost Test (UCT/PACT) and a Participant Cost Test (PCT). The secondary tests were conducted to further inform regulatory decision-making. The UCT/PACT provides additional information on the cost-effectiveness of the DER use case from the perspective of the hypothetical IOU, illustrating its cost-effectiveness even when host customer impacts are not accounted for. The PCT provides additional information to help inform program design (e.g., the level of financial incentives to offer prospective participants) by providing insights into energy bill impact on participants.

2.5.1 Summary - Primary JST vs Secondary Tests

Table 2.6 illustrates a comparison of the value streams modeled for each of the three (3) tests and identifies if an impact is a benefit or a cost for a specific test, or if it is not applicable due to cost-effectiveness test parameters. For example, the PCT does not include electric utility system impacts, and the UCT does not include host customer impacts.[50]

Table 2.6: Comparison Summary of Primary JST and Secondary Tests

Cost Effectiveness Tests	JST	UCT	PCT
UTILITY SYSTEM IMPACTS			
Avoided Energy	Benefit	Benefit	Not Applicable
Avoided Generation Capacity	Benefit	Benefit	Not Applicable
Avoided T&D	Benefit	Benefit	Not Applicable
Avoided Ancillary Services	Benefit	Benefit	Not Applicable
Avoided RPS (Cap & Trade)	Benefit	Benefit	Not Applicable
GHG Adder	Benefit	Benefit	Not Applicable
GHG Rebalancing	Benefit	Benefit	Not Applicable
Reduced Risk	Benefit	Benefit	Not Applicable
Customer Reliability	Benefit	Not Applicable	Benefit
Utility Program Incentive	Cost	Cost	Benefit
Utility Program Admin	Cost	Cost	Not Applicable
HOST CUSTOMER IMPACTS			
State SGIP Tax Incentive	Benefit	Not Applicable	Benefit
Federal Tax Credit	Benefit	Not Applicable	Benefit
Customer Bill Savings	Not Applicable	Not Applicable	Benefit
Depreciation	Benefit	Not Applicable	Benefit
Customer NEBs	Not Applicable*	Not Applicable	Benefit
Customer BESS Net Capital Cost	Cost	Not Applicable	Cost
Customer O&M Impacts	Cost	Not Applicable	Cost
BESS Interconnection Cost	Cost	Not Applicable	Cost
*Not applicable for this use case, but part of the Jurisdiction's primary JST that applies to all DERs.			

[50] For additional information on JST, UCT/PACT and PCT evaluations see the NSPM for DERs Appendix E.

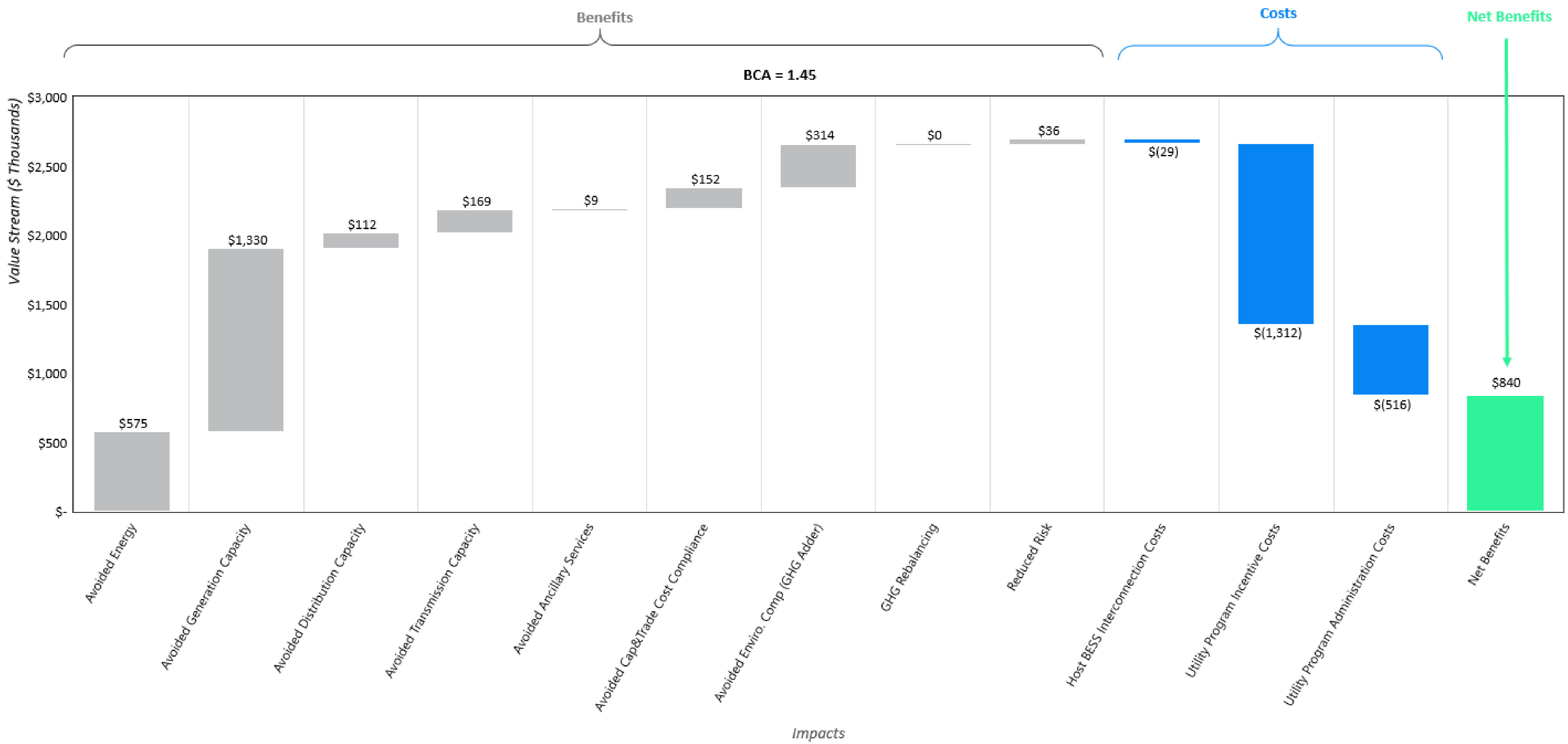
2.5.2 Analysis Results for Secondary Tests

All secondary test benefit and cost calculations and sources are based on the same data utilized for the JST.

Utility Cost Test/Program Administrator Cost Test (UCT/PACT) - The UCT/PACT measures the benefits and costs of the BTM commercial solar + storage program from the perspective of the entity implementing the program, which in this case is an IOU (other examples can include a government agency, nonprofit, or other third party). The UCT/PACT benefit-cost ratio (1.45) is largely driven by benefits from avoided generation capacity and energy costs, in addition to avoided environmental compliance costs. Figure D shows the UCT/PACT BCA results.

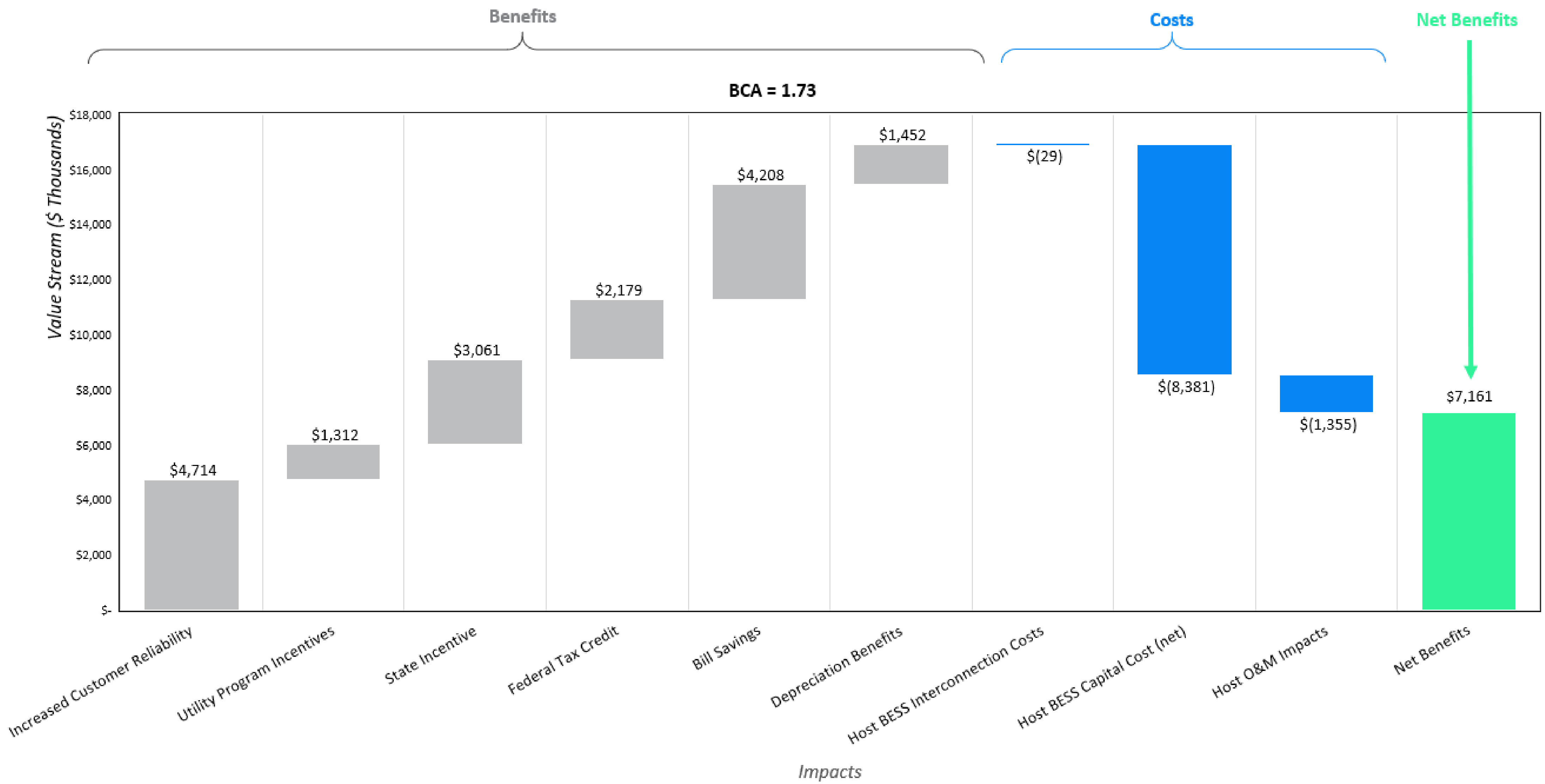
Participant Cost Test (PCT) - The PCT measures the benefits and costs of the BTM commercial solar + storage program from the perspective of the customer participating in the solar + storage program. The PCT's high benefit-cost ratio (1.73) is largely driven by benefits from the state incentive, increased customer reliability, and bill savings. Figure E shows the PCT BCA results.

Figure D: UCT/PACT Benefit-Cost Value Streams and Net Benefits



Key: Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

Figure E: PCT Benefit-Cost Value Streams and Net Benefits



Key: Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

2.6 Conclusions and Areas for Further Research

This case study illustrates the importance of ensuring that, if a jurisdiction's policy calls for the inclusion of host customer impacts, then both the full range of applicable host customer impacts should be considered, both costs and benefits, to ensure symmetry and avoid bias in the BCA. In this case study, increased host customer reliability from the BESS is the single largest benefit stream quantified. This demonstrates the importance of quantifying all impacts of the DER under consideration, and the importance of doing so in a reliable, defensible way.

This case study also emphasizes the important treatment of tax incentives and depreciation benefits relative to the JST. In this case study, the regulatory perspective for the JST accounts for the three most impactful value streams (federal tax credit, state incentive, and depreciation benefits) as a host customer benefit. If the JST regulatory perspective had been a broad societal perspective, these benefits would be treated as an offset by their cost to society in the form of taxes. How a jurisdiction selects their JST should not be based on trying to influence the results for any one type of DER (or bias towards DERs in general) but should be reflective of the values and policies of the jurisdiction.

Finally, this case study showcases the need for further research into hard to quantify value streams such as host customer risk, for which there is not a wide base of literature to accurately access these impacts.[51]

[51] For additional information on accounting for risk, see: MTR Handbook.

3. Residential Grid-interactive Efficient Building Retrofit in the Mid-Atlantic

This case study applies the NSPM for DERs principles and guidance to a BCA for a hypothetical GEB retrofit program including the following measures:

- ceiling insulation upgrades and air sealing;
- an ASHP to replace a natural gas furnace and central AC; and
- a smart thermostat that is automatically enrolled in a DR program.

This case study serves as an illustrative example to inform and guide BCA approaches for GEB retrofit programs.

3.1 Introduction

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.[52] 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.[53] 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.[54]

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

[52] Source: https://www.energy.gov/eere/buildings/articles/meet-does-newest-connected-communities-grid-interactive-efficient-buildings

[53] 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., & Nemtzow, 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

[54] 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

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.

3.2 Case Study Context and Assumptions

This case study evaluates the cost-effectiveness of a hypothetical GEB retrofit program proposed by a municipal utility located in the Mid-Atlantic region. It evaluates the incremental impact of an incentive-driven retrofit program for residential customers that install EE, DR, and building electrification measures. 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

3.2.1 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 Mid-Atlantic region,[55] including a significant presence of coal-fired power plants for baseload and marginal natural gas peaker plants. 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, NOX);

[55] For additional information, see: https://www.pjm.com/

- Promote beneficial electrification, including programs that enable fuel switching;[56] and
- Comply with state's RPS to diversify the generation mix, including an increase in renewable energy (RE) over time.[57]

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;[58]
- 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.

Table 3.1: Summary of Impacts Included in GEB Retrofit Case Study

Category/Type	GEB Retrofit Case Study (JST 3)
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	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

[56] 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

[57] 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

[58] 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.

3.2.2 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 3.2:

- 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 [59]
- 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
    - Building electrification: Installing an ASHP[60] to replace the natural gas furnace and central AC[61]
    - 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 3.2: 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

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

[60] The ASHP was not assumed to be a cold climate heat pump.

[61] The case study assumed installation of backup electric resistance strip heating.

Assumption Category	Assumption Description	Value/Assumption
		• 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
Reference Case	Current Residential Home	A 2,500 sq. ft single family home with: central AC[62] 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 AC[63] • 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

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

[63] 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
		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 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, the tables 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.[64]

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.

[64] 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.

Table 3.3: 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 *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.[65]
	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.[66]
	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.[67]
	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.[68]

[65] Source: https://s3.amazonaws.com/ilsag/AvoidedEnergyCostsinMaryland1.pdf

[66] Source: https://s3.amazonaws.com/ilsag/AvoidedEnergyCostsinMaryland1.pdf

[67] Source: https://s3.amazonaws.com/ilsag/AvoidedEnergyCostsinMaryland1.pdf

[68] Source: https://s3.amazonaws.com/ilsag/AvoidedEnergyCostsinMaryland1.pdf

Type	Specific Impact	Data Description & Rationale
	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.
	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. [69]
	Reliability	While part of the JST for this jurisdiction, no value included because the DER doesn't reduce utility expenditures on reliability.[70]
	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.

[69] 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

[70] 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.

Table 3.4: 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.
	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.
Transportation	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 3.5: 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

System Impact	Specific Impact	Data Description & Rationale
		electrification measures.[71] 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.[72]
	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	While part of the jurisdiction's JST, no value included because there are no impacts associated with this DER program / use case.
	Reliability	
	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.[73]
	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.[74]
	Productivity	
	Economic Well-being	
	Comfort	
	Health & Safety	
	Empowerment & Control	
	Satisfaction & Pride	

Table 3.6: 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).

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

[72] Source: HomeGuide

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

[74] 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

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 tests[75]:

- 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.[76]

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 3.3-3.6 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

[75] See MTR Handbook - Chapter 3.2.6 and Chapter 7.1.

[76] See MTR Handbook - Chapter 3.2.6 and Chapter 7.1.

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 COBRA[77] 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)[78] 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 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.

3.4 BCA Results

3.4.1 Summary of Inputs & Calculated Values

As outlined in Tables 3.2 – 3.6, 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 3.7:

[77] Source: https://www.epa.gov/cobra

[78] Source: https://www.epa.gov/statelocalenergy/estimating-health-benefits-kilowatt-hour-energy-efficiency-and-renewable-energy

*Summary of Relevant Value Streams for Jurisdiction-Specific Test**			
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

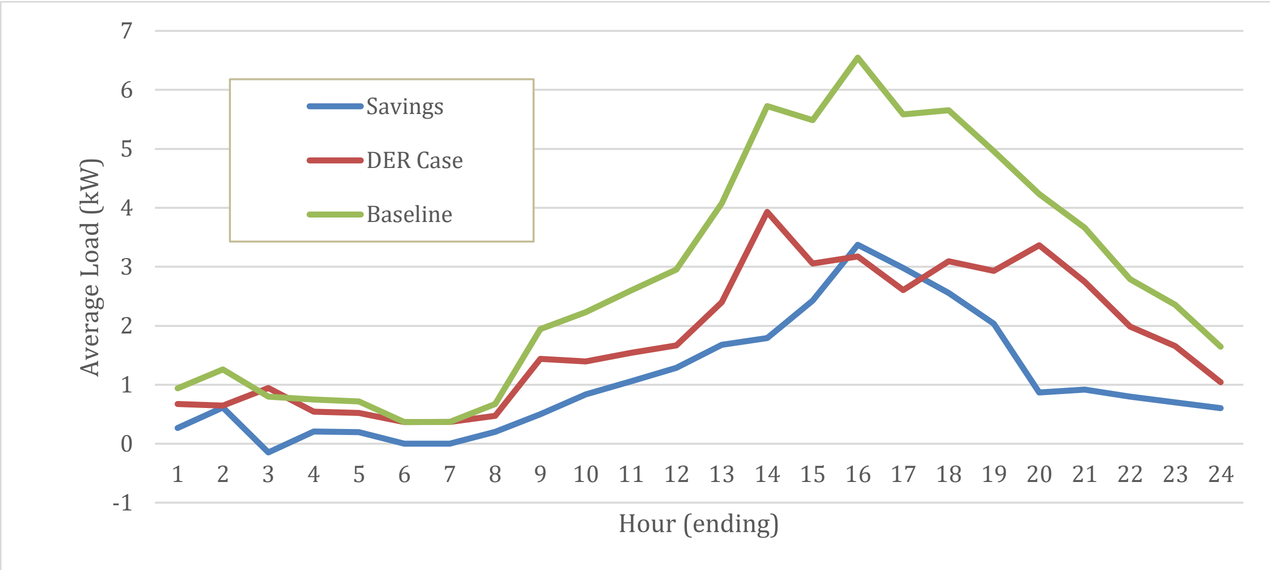
*As noted in Tables 3.3-3.6, some impacts that are part of the jurisdiction's primary JST are not included in the BCA because either the impact is not relevant to this use case or is immaterial in impact.

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, is it 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 F: 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 3.7: 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)
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

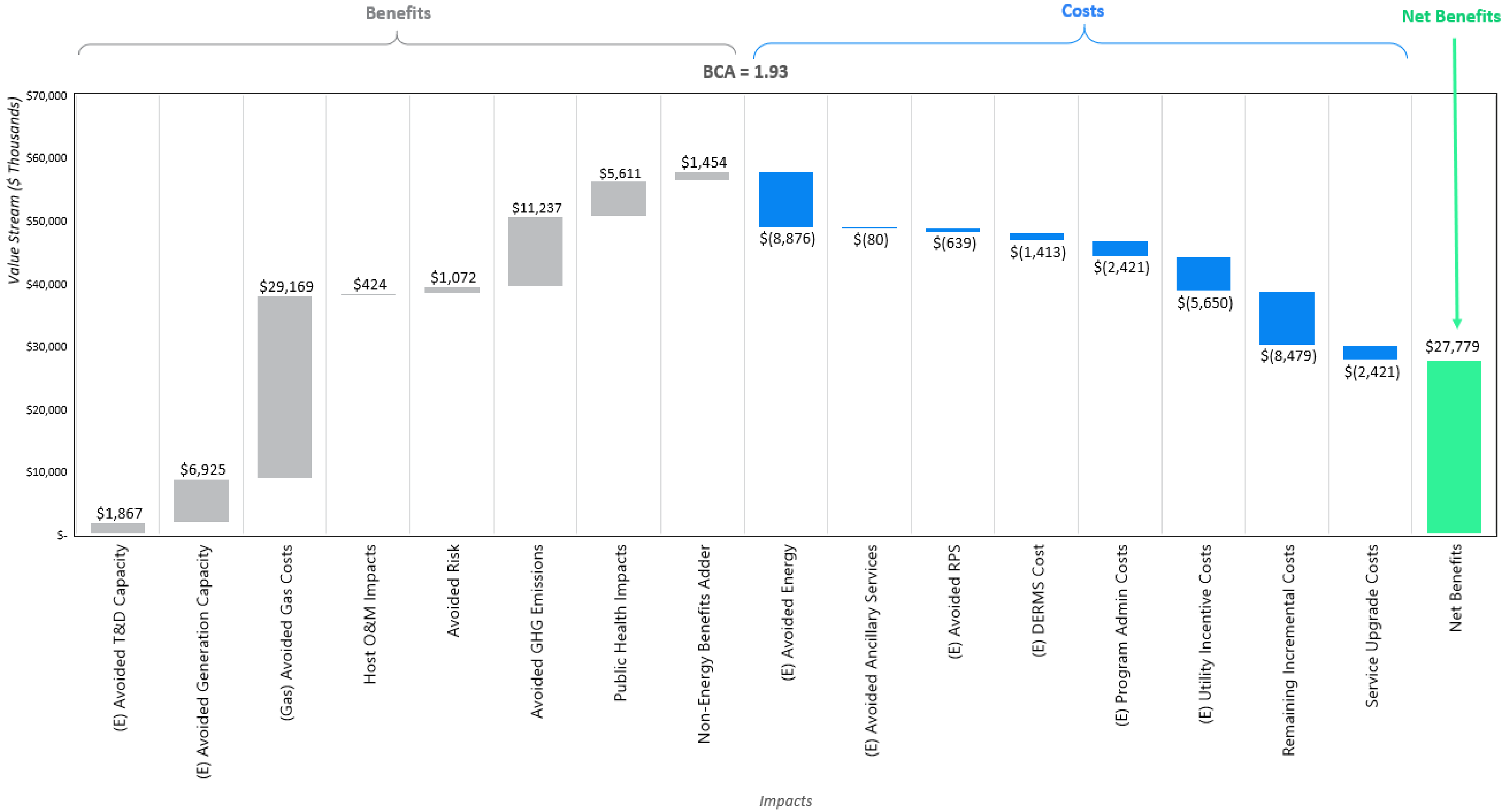
Value Stream	Net Present Value ($ 2021)
Service Upgrade Costs	$ (2,421,464)
Avoided Risk	$ 1,072,037
Non-Energy Benefits Adder	$ 1,454,207
SOCIETAL IMPACTS	
Avoided GHG Emissions	$ 11,237,119
Public Health Impacts	$ 5,610,915
Total Benefits	**$ 57,758,374**
Total Costs	**$ (29,979,627)**
Net Benefits	**$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.

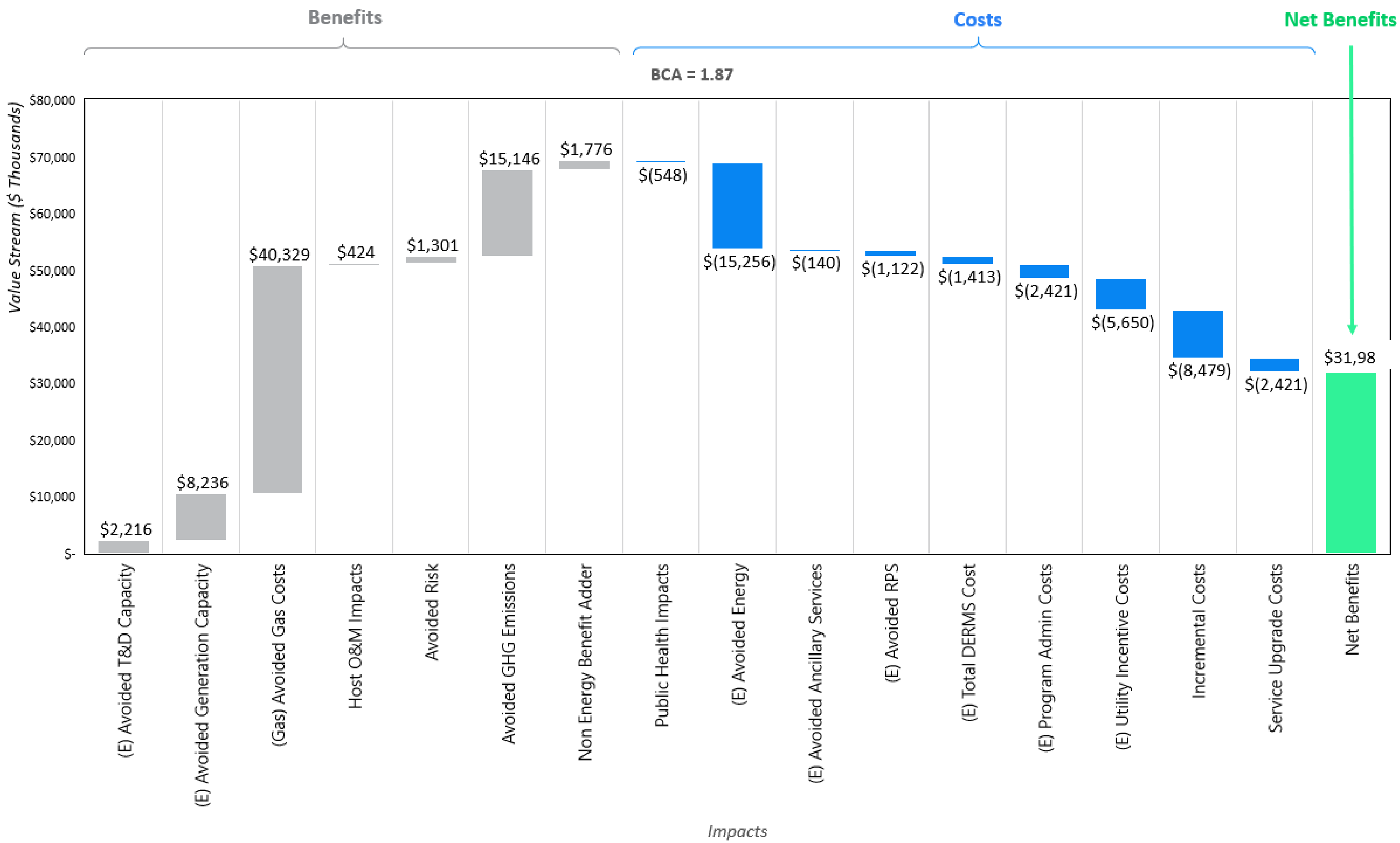
Figure H illustrates the BCA results with interactive effects included, while Figure I shows the BCA results with interactive effects *not* included, with a benefit-cost ratio of 1.87 and net benefits of $31,975,978.

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



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

3.4.2 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.[79]

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.

[79] 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. .

3.4.3 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.

4. Additional Considerations

4.1 DER Use Case Impact

As illustrated in this set of case studies, 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.

4.2 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 the accurate data for quantifying the value stream is not proportional to the scale of the impact (such as the approach taken in the EV managed charging case study to GHG emissions).

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.