Commercial Solar and Storage Controlled Dispatch in the West

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

June 2022 – Updated 2025

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1. Introduction and Overview of Case Study

The purpose of this report is to illustrate a benefit-cost analysis (BCA) for a specific distributed energy resource (DER) technology and a use case that is of growing interest in the electric industry: commercial solar + storage controlled dispatch.

> Commercial solar + storage is defined here as a 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.

As U.S. regulators and utilities focus on addressing evolving concerns over grid reliability and flexibility, paired behind-the-meter (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.[1] For non-residential battery storage installations through 2020, approximately 40% were paired with solar (versus residential BTM energy storage's rate of approximately 80%).[2,3] Additionally, within the non-residential sector, for-profit commercial entities make up the majority of all paired solar + storage installations, at 70%.[4] 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.

This case study is informed by a real-world BCA and data for a similar use case but has been generalized into an illustrative and hypothetical example for broader applicability. It was developed to demonstrate key factors and challenges with conducting BCA for distributed generation (DG) and distributed storage resources in a multiple on-site DER use case. In addition, this case study illustrates key BCA considerations for a multi-DER use case and

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[1] 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.

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

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

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

demonstrates a specific approach to account for impacts when certain data may be unavailable.[5]

The case study applies guidance from the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM).[6]

2. National Standard Practice Manual

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (2020)* ("NSPM for DERs" or "NSPM") provides a comprehensive framework for the cost-effectiveness assessment of DERs.[7] The manual offers a set of policy-neutral, non-biased, and economically sound principles, concepts, and methodologies to support single and multi-DER benefit-cost analysis. It is intended for use by jurisdictions to help inform which resources to acquire to meet their specific policy goals and objectives using a primary cost-effectiveness test, and it also provides guidance on the use of secondary tests.

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

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

[5] 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.

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

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

Table 1: NSPM BCA Principles

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

Key NSPM principles applied to this case study include:

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

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

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

BCA Impacts

The key impact categories for 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 Appendix A

This case study addresses the full range of electric utility system impacts. The extent to which non-utility system impacts apply is dependent on the applicable policy goals of the hypothetical jurisdiction. As such, this case study presents a jurisdiction-specific test (JST). A JST may or may not align with traditional cost-effectiveness tests (e.g., Utility Cost Test/Program Administrator Cost Test, Total Resource Cost Test, or Societal Cost Test).[8]

3. 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 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.

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

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

The 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.[9] 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 3.3.[10] A summary of the impacts accounted for in this case study BCA is provided in Table 2.

[9] 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

[10] 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 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: Summary of Impacts Included in Solar + Storage Case Study

Category/Type	Solar + Storage Case Study (JST Impacts)
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

3.2 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 3:

- 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 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.

Table 3: 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)

Assumption Category	Assumption Description	Value/Assumption
	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[11] 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[12] ● 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
	Program Customer Type	Commercial (small office building) with regular daytime operations
	Rate Class	Small to medium Commercial & Industrial (C&I) TOU rate class[13]
	Program Offering Time Period/Length	3 years

[11] 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

[12] 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

[13] 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

Assumption Category	Assumption Description	Value/Assumption
	Contract Length for TOU rate	10 years
	Measure Life	10 years for BESS[14]
	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%[15]

3.3 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 4 and 5 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.[16]

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.

[14] 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/

[15] 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).

[16] 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 4: 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[17] and GHG Rebalancing[18] 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.

[17] 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

[18] 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.[19]
	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.[20]
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.

[19] 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.

[20] 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.[21]
	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.[22] 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 5: 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.[23] O&M costs were also calculated based on EPRI estimates[24] 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.

[21] 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

[22] Reliability metrics including SAIFI, CAIDI, and SAIDI inform a utility's annual reliability performance and expenditures. Source: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2020-pge-2020-annual-electric-reliability-report.pdf

[23] 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

[24] 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. [25] 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.[26] 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.[27] State financial incentives are realized based on California's Self-Generation Incentive Program (SGIP). While the SGIP incentive is $350/kWh[28] 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.[29]

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

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

[26] Source: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2021-pge-annual-electric-reliability-report.pdf

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

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

[29] 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 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.[30]

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.[31] Customer reliability calculations analyzed the average building load and BESS state of charge.[32] A uniform distribution of outages was assumed, with an average 2-hour outage duration per customer and 4-hour hold-over time per customer.

4. BCA Results

4.1 Summary of Inputs & Calculated Values

As outlined in Table 4 and Table 5 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 6 and BCA results provided in Table 7.

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

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

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

Table 6: Summary of Relevant Value Streams

*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 4 and 5, 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.

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.

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[33] 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.[34] 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).

[33] 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.

[34] As optimally sized by NREL REopt simulations.

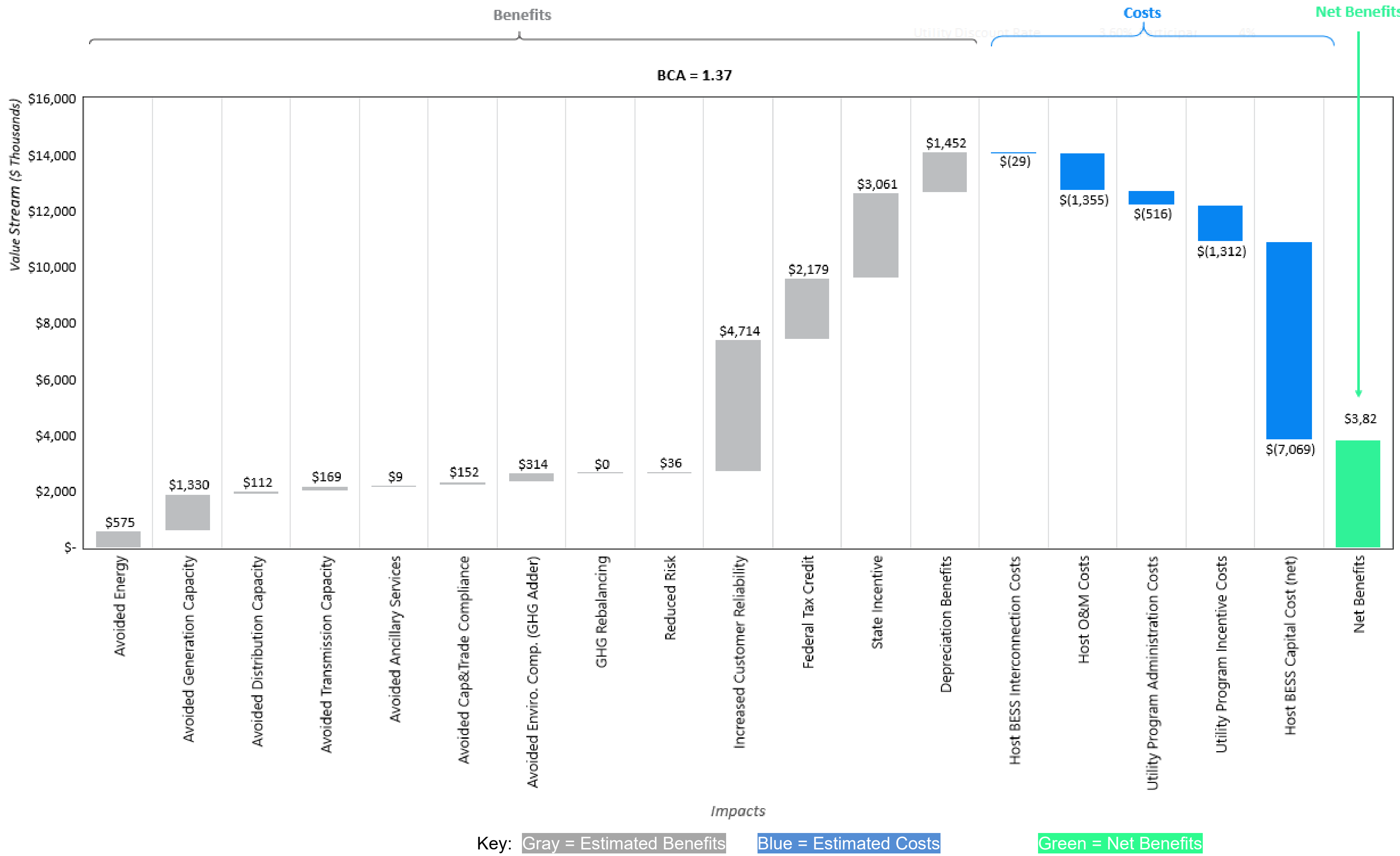
Table 7: Solar + Storage JST: BCA Values and Results

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 A illustrates the BCA results for the Commercial Solar + Storage JST.

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



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.

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.

5.1 Summary - Primary JST vs Secondary Tests

Table 8 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.[35]

Table 8: 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.			

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

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

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 B 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 C shows the PCT BCA results.

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

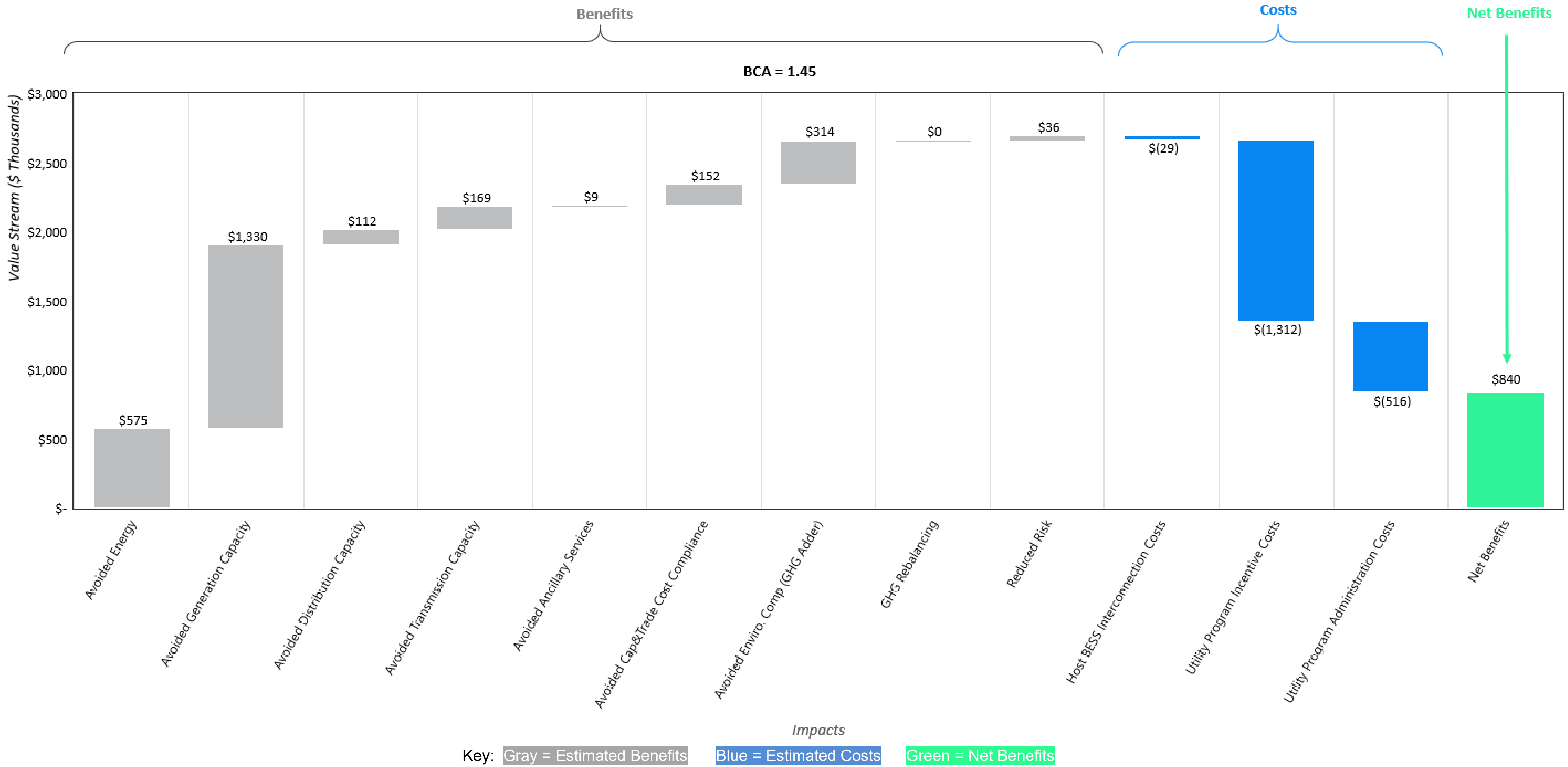
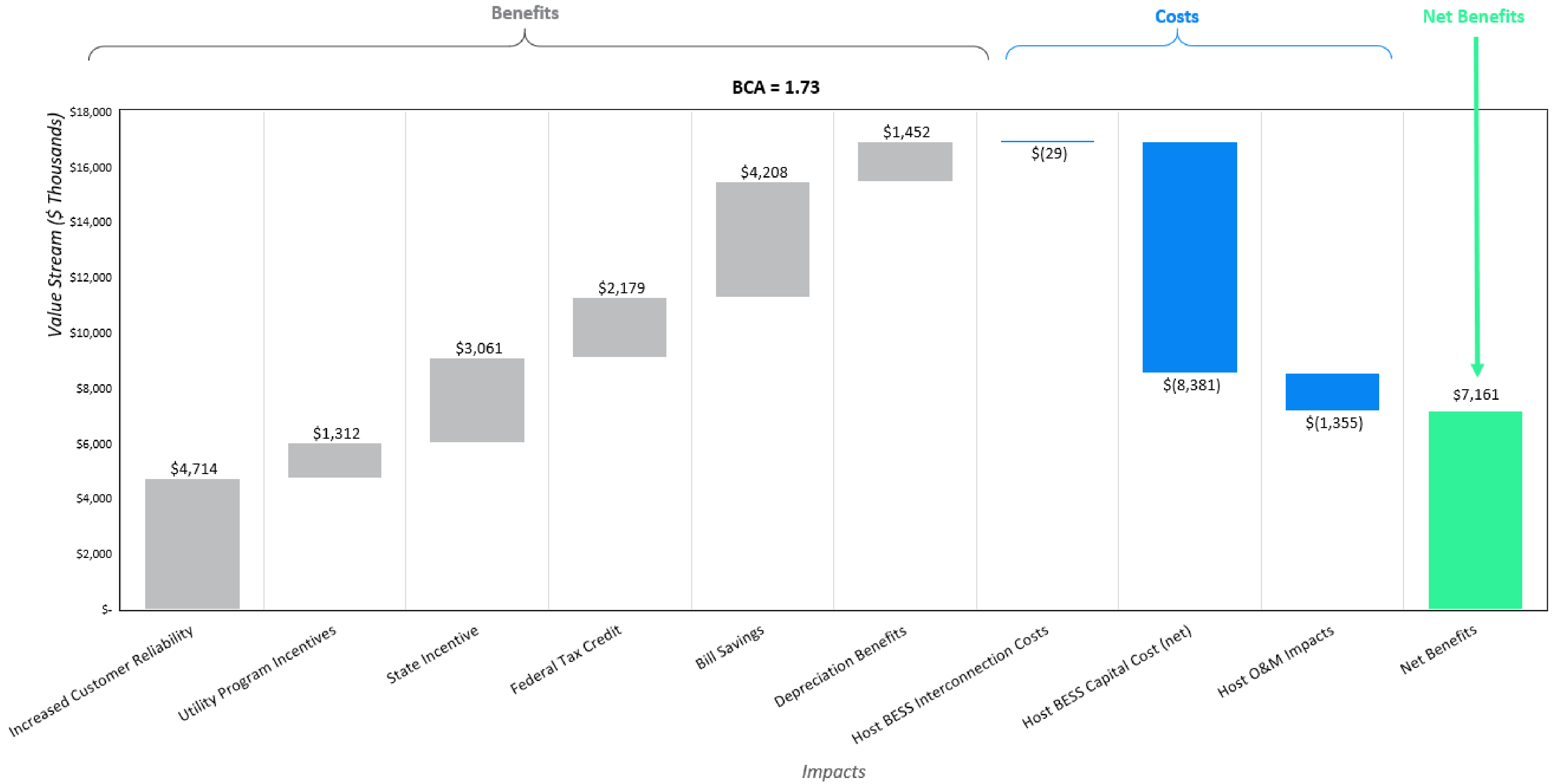


Figure C: PCT Benefit-Cost Value Streams and Net Benefits



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

5.3 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.[36]

6. Additional Considerations

6.1 DER Use Case Impact

As illustrated in this case study, benefit-cost results are heavily dependent on the DERs and use case 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.

6.2 Accounting for Hard to Quantify Impacts

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

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[36] For additional information on accounting for risk, see: [MTR Handbook.]()

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

Appendix – BCA Impact Categories

Electric Utility System Impacts.[37]

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

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

Gas Utility System and Other Fuel Impacts

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

Other Fuel Impacts

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

Host Customer Impacts

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

Societal Impacts

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