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REGULATORY ASSISTANCE PROJECT

Using Benefit-Cost Analysis to Improve Distribution System Investment Decisions

Issue Brief

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I. Introduction[1]

This issue brief explores the many opportunities for electric utilities and public utility regulators to use benefit-cost analysis techniques to evaluate potential investments. The foundational premise of the issue brief is that these techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods. Benefit-cost analysis is, to put it simply, a superior tool to other analytical methods in many (but not all) cases. Increasing its use in utility regulation can result in better outcomes for ratepayers and society.

Benefit-cost analysis techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods.

For those interested in a more thorough treatment of this topic, we are simultaneously publishing a reference report as a companion to this issue brief that offers more detail on the subjects covered herein as well as examples from state regulatory proceedings.[2]

[1] The authors wish to thank the following people for providing helpful insights into early drafts of this issue brief: Tim Woolf, Synapse Energy Economics, and Patrick Hudson, Michigan Public Service Commission staff (retired). Ruth Hare and Steena Williams of RAP provided editorial support.

[2] Shenot, J., Prause, E., & Shipley, J. (2022). *Using benefit-cost analysis to improve distribution system investment decisions: Reference report.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/using-benefit-cost-analysis-improve-distribution-system-investment-decisions-reference-report

Background

Historically, utility regulators have exercised relatively limited oversight with respect to the maintenance and operation of the electric distribution system. For the most part, regulators have relied on utility experts to make prudent decisions about investments in the distribution system that are necessary to accommodate growth, replace failing assets and ensure power quality. During rate cases, past utility investments may be reviewed for prudence and future distribution system spending budgets may be determined as part of establishing the revenue requirement, but individual distribution system investment options are rarely scrutinized.

For a variety of reasons, regulators in recent years have increasingly turned their attention toward the distribution system:

- Some utilities, particularly those in restructured states, do not own generation assets and might not own transmission assets, yet their operation of the distribution system is still regulated by a state public utility commission (PUC) or public service commission (PSC).
- The vast majority of service outages occur due to problems on the distribution system, not because of problems on the high-voltage transmission system or inadequate generation resources.
- Among investor-owned electric utilities throughout the United States, distribution system spending is increasing as a share of total utility capital investment and operational expenses.
- Investment in distributed energy resources (DERs)[3] has grown rapidly.
- In addition to building out the system to accommodate load growth, and replacing aging or failing assets, new utility investments are needed to modernize the grid — especially at the distribution system level.

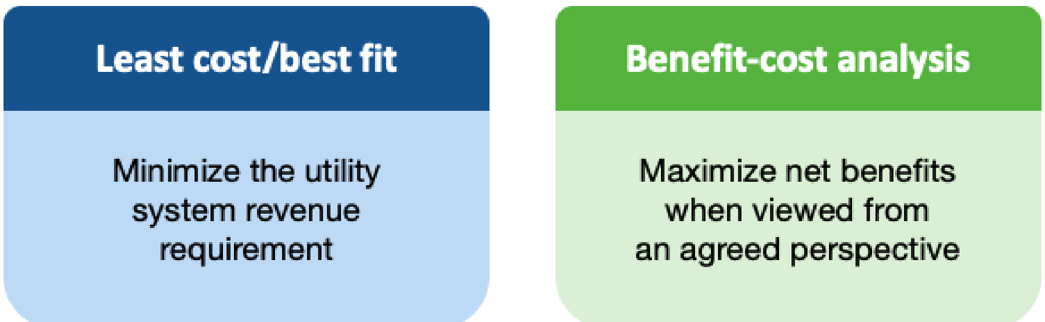
Regulators today are paying closer attention than ever to individual distribution system investment decisions, more frequently requiring utilities to transparently evaluate alternatives to meet customer needs, and increasingly requiring utilities to file long-term distribution system plans (DSPs). This increased scrutiny is sometimes applied to traditional distribution system assets like substations and transformers but is even more likely to be used to evaluate "grid modernization" investments.

[3] States vary in how they define DERs. Most states limit this term to resources interconnected to the distribution system or operating behind the customer's meter. In terms of resource types, most DER definitions encompass a subset of energy efficiency, demand response or "flexible loads," distributed generation, distributed energy storage, microgrids and electric vehicles.

Two Common Approaches to Evaluating Utility Investments

This issue brief compares two analytical approaches that can be used to evaluate utility investments in DERs and the distribution system and ensure that investments in grid modernization are smart: least cost/best fit (LCBF) techniques and benefit-cost analysis (BCA) techniques. Figure 1 summarizes the approaches.

Figure 1. Two analytical approaches to evaluating investments



Least cost/best fit: We categorize analytical methods as LCBF if decisions are made by comparing the total costs of investment alternatives over a defined period of time, including capital costs as well as operations and maintenance costs, and identifying the options that minimize the net present value of the revenue requirement associated with the entire power system, or in some cases just a portion of the power system (e.g., just the transmission system).

Occasionally, an option may be chosen that isn't technically the least cost solution (doesn't minimize the revenue requirement) but is considered the best fit — for example, because it reduces uncertainty about future operations and maintenance costs. The benefits associated with each investment alternative do not need to be identified or quantified. LCBF methods are typically used when action is needed, or presumed to be needed, and the goal is simply to minimize the cost.

Historically, utilities have relied on LCBF techniques to make decisions about investments in utility-owned infrastructure like power plants, transmission lines, substations or systems monitoring equipment or to evaluate power purchase agreements and other utility contracts with vendors. After the utility identifies something that is needed to maintain safe and reliable electric service or extend service to a new area, it then seeks the least costly way to meet the identified need in a manner that complies with all applicable legal requirements.[4]

[4] Options that do not satisfy all applicable legal requirements are not considered "solutions" to an identified need. This distinction is important but easily overlooked. For example, if a utility is subject to a renewable portfolio standard, it will seek to minimize the costs of meeting customer demand *while complying with that standard*. This is consistent with minimizing the revenue requirement because utilities include the costs of complying with legal obligations in the revenue requirement.

Benefit-cost analysis: In contrast, we apply the term BCA to methods that compare the costs and benefits of investment alternatives to assess and *maximize the net benefits* (i.e., benefits minus costs) when viewed from an agreed perspective.[5] This can include situations where the options being considered include the status quo or a "take no action" alternative.

For decades, utilities, PUCs and independent evaluators have used BCA methods to assess whether certain types of utility expenditures will be (or in retrospective evaluations, were) cost-effective. The most common and widespread use of BCA has been for evaluating utility programs offered to customers, such as incentive programs that support energy efficiency or other DERs. BCA has also been used in many cases to evaluate utility investments in new technologies, such as advanced metering infrastructure, or other assets.

Before going any further, we must acknowledge that the lines separating LCBF methods from BCA methods can be blurry. There are at least two reasons for this:

1. Some of the benefits of almost any utility program or investment come in the form of reducing the revenue requirement — for example, by reducing total systemwide demand or peak demand through an energy efficiency program. When benefits come in the form of reducing the revenue requirement, they are considered in both LCBF and BCA methods. But benefits that don't reduce the revenue requirement, such as increases in homeowner comfort or employee productivity that might result from some energy efficiency measures, are usually not considered in an LCBF approach.

2. In some cases the "best fit" part of an LCBF-based decision may take into consideration costs and benefits that have nothing to do with the revenue requirement, such as reductions in greenhouse gas emissions beyond any existing legal requirements.

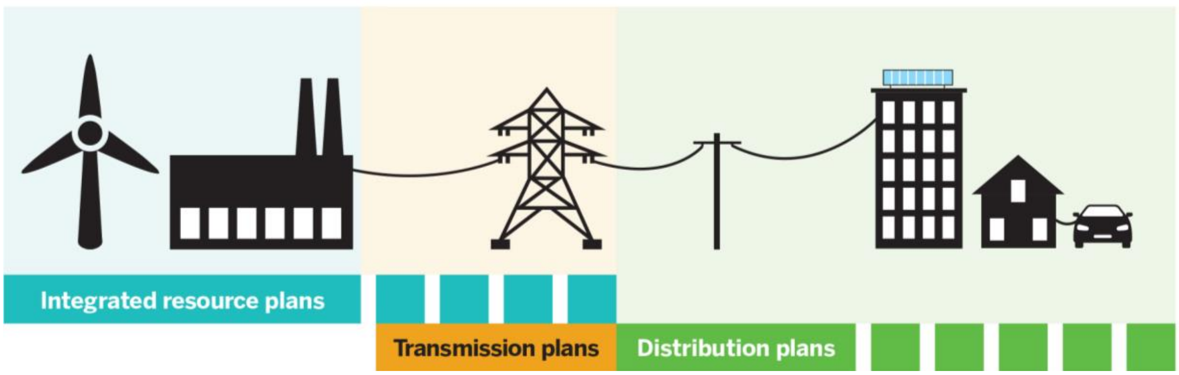
Regardless of any differences over terminology or the way we've characterized LCBF and BCA, we hope readers will agree there are differences between these two methods and opportunities to use BCA in new and better ways to improve decisions.

[5] The perspectives that might be considered are explained in more detail in Section III of this issue brief.

II. Use of LCBF Techniques in Utility Planning

Many utilities are required by state laws, state rules or PUC orders to prepare and file detailed long-term investment plans for satisfying their customers' demand for electricity. Other utilities not subject to these requirements may develop similar plans for internal use. Long-term planning processes have historically focused on only one part of the electric power system at a time (see Figure 2).

Figure 2. Scope of typical long-term planning processes by electric utilities



- Integrated resource plans (IRPs) typically focus on generation resource adequacy, though they sometimes also address transmission capacity needs associated with acquiring new generation resources.
- Transmission plans focus on ensuring adequate transmission capacity to serve peak demands and, in some cases, relieving congestion between low-cost generation resources and load centers.
- Distribution system plans focus on minimizing distribution system costs, but generation and transmission costs may be considered as well. DSPs are a relatively new development for utility commissions, with a small number of states instituting a regulated DSP process in the past few years and additional states now developing rules or investigating distribution system planning. Prior to these recent developments, DSP activities in virtually all jurisdictions were conducted by utilities in-house with little or no regulatory oversight or transparency. DSP processes vary from state to state in terms of which types of investments fall under the scope of the planning process.

In each case, LCBF techniques are normally used to make most planning decisions, though there are many examples (as we will see later in this issue brief) of using BCA methods in concert with LCBF.[6] DSP processes are more likely than integrated resource planning or transmission planning to incorporate benefit-cost analysis — for example, as a way of testing whether DERs can cost-effectively substitute for some infrastructure investments.

[6] And, as previously noted, non-utility-system costs and benefits may sometimes be evaluated in these plans to arrive at the "best fit" solution.

III. Use of BCA Techniques

Benefit-cost analyses are used to assess whether an expenditure a utility is considering (or has already made) is cost-effective. An expenditure is cost-effective if its lifetime benefits exceed its lifetime costs, as examined through an agreed perspective and cost test. BCA techniques are routinely used to evaluate utility demand-side management programs in most states and are sometimes used to evaluate other types of programs or expenditures.

The essence of BCA is a comparison of two or more potential courses of action. The analyst first looks at the marginal impacts (ideally, long-run marginal impacts) of a proposed expenditure on grid capacity needs and how the power system is operated, when compared to an assumed reference case. The analyst then looks at the costs or avoided costs associated with those marginal impacts. Depending on the cost test used, additional non-utility-system costs and benefits (or avoided costs) may also be assessed.

The essence of BCA is a comparison of two or more potential courses of action.

Perhaps the most crucial decision that must be made before conducting any BCA is the selection of a perspective from which to evaluate costs and benefits. This is because some of the costs and benefits of an expenditure can look different when viewed from different perspectives.

For decades, state PUCs have borrowed ideas from a BCA manual published by the California Public Utilities Commission and adapted them to meet their own needs. The *California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects*[7] defines five cost-effectiveness tests and offers a standard methodology for conducting each test. Each test considers the question of cost-effectiveness from a different perspective.

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM) is the most up-to-date reference available on BCA principles.[8] A key contribution of the NSPM is that it offers a structured framework and set of guiding principles for states to develop their own jurisdiction-specific test (JST). Table 1 on the next page compares the JST with traditional cost tests described in the *California Standard Practice Manual*.[9]

[7] California Public Utilities Commission. (2001). *California standard practice manual: Economic analysis of demand-side programs and projects*. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf

[8] National Energy Screening Project. (2020). *National standard practice manual for benefit-cost analysis of distributed energy resources*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[9] Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A framework for evaluating the cost-effectiveness of demand response*. U.S. Department of Energy and Federal Energy Regulatory Commission. https://www.ferc.gov/sites/default/files/2020-04/napdr-cost-effectiveness.pdf; and National Energy Screening Project, 2020.

Table 1. Cost-effectiveness tests

Test	Perspective	Key question answered	Impacts accounted for
Participant cost test[10]	Customers participating in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers in the program
Ratepayer impact measure[11]	Impacts on rates paid by all customers	Will utility rates be reduced?	Includes the benefits and costs that will affect utility rates, including utility system benefits and costs plus lost revenues
Program administrator cost test/ utility cost test	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total resource cost test	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the benefits and costs experienced by the utility system, plus benefits and costs to program participants
Societal cost test	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Jurisdiction-specific test	Regulators or decision-makers	Will the cost of meeting utility system needs while achieving policy goals decrease?	Includes utility system costs and benefits and any additional costs and benefits associated with achieving applicable policy goals

Sources: Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A Framework for Evaluating the Cost-Effectiveness of Demand Response*; and National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Every state that mandates energy efficiency programs currently uses one or more of the tests identified in Table 1 to evaluate programs and projects, albeit in some cases with state-specific modifications. Most states designate one of the tests as their primary test for making decisions. Current state practices for evaluating energy efficiency programs can be compared by reviewing the *Database of State Practices* maintained by the sponsors of the NSPM.[12] It details which cost tests are used and how they are applied in each state.

[10] The participant cost test provides useful information about whether participating customers will save money and thus the likelihood that customers will participate in the program, but it is not helpful for deciding whether the utility should offer the program and is never used as a primary test.

[11] The ratepayer impact measure is identical to the program administrator cost test, except that the ratepayer impact test also treats utility lost revenues as a cost. As explained in the NSPM, evaluating the potential impacts of a DER program on retail rates is subtly different from a true benefit-cost analysis and should be conducted only as an adjunct to other cost tests, never as a primary test.

[12] National Energy Screening Project. (2021, April 1). *Database of screening practices*. https://www.nationalenergyscreeningproject.org/state-database-dsp/

IV. Comparing LCBF and BCA as Investment Decision-Making Tools

LCBF methods begin with an attempt to find the least cost solution to identified resource or grid needs from the utility perspective. The least cost solution is then modified in some cases to select a best fit solution that is not strictly least cost under assumed baseline conditions. But for now, consider a case where the least cost solution is in fact also the best fit solution. What would we expect to happen if alternative or additional expenditures are proposed and subject to BCA?

If the LCBF exercise considered every potential solution to grid needs, if the BCA used the program administrator cost test/utility cost test (UCT),[13] and if the two types of analysis used the same data assumptions, then in theory none of the proposed alternative or additional expenditures would pass the test. In other words, if LCBF yields a least cost solution for the utility system, then the proposed expenditures subject to BCA won't reduce utility system costs (i.e., the revenue requirement). One might then argue that BCA is unnecessary at best and a waste of time and resources at worst. But this is where theory runs into the reality of LCBF and BCA techniques. The two techniques can lead to divergent conclusions for the following reasons, which we explain in more detail in this section:

- Use of costs tests other than the UCT.
- Practical limitations of power sector modeling.
- Timing of different evaluations.
- Level of detail in analysis/modeling.
- Differences in whether the evaluation looks holistically across the generation, transmission and distribution portions of the power system.

First, one must start by acknowledging that as of August 2022, only six jurisdictions used the UCT as their primary test, according to the *Database of State Practices*. The moment one considers using a test other than the UCT, the biggest differences between BCA and LCBF become readily apparent. BCA quantifies all costs and benefits relevant under the chosen cost test, while LCBF (as we use the term in this issue brief) quantifies avoided utility system costs but no other categories of relevant benefits.[14] BCA allows for decisions that maximize net benefits, while LCBF allows only for decisions that minimize costs.[15] If an action will have significant non-utility-system benefits that are included in the cost test

[13] The term "utility cost test" is frequently used as a substitute or synonym for the program administrator cost test in recognition of the fact that most customer-facing programs are in fact administered by utilities. There is no methodological difference.

[14] Again, we acknowledge that others may define LCBF differently. For example, some jurisdictions may impute a cost per ton of greenhouse gas emissions, which is not actually part of the utility system revenue requirement, and include the imputed costs in what they call a least cost or LCBF decision-making framework. However, this is not an LCBF as we define the term in this issue brief, but rather an example of using BCA concepts to supplement LCBF results, which we encourage. In any event, it is an example of how the lines between LCBF and BCA can be blurry.

[15] While it is possible that the best fit adjustment to a least cost evaluation might replicate some aspects of a total resource cost test, societal cost test or JST framework, the non-utility-system impacts included in those tests can be more accurately and more transparently accounted for using BCA techniques, because one only needs to quantify the marginal impacts from specific proposed expenditures rather than trying to quantify the non-utility-system impacts of all potential expenditures.

chosen by a jurisdiction, the action could easily maximize net benefits while not minimizing costs.

Even in states that use the UCT as their primary test, there are still several reasons why BCA and LCBF may lead to different conclusions. In practice, it is virtually impossible to construct workable models for planning processes that consider every potential solution to every potential need. This problem is addressed through two common shortcuts:

Assuming that existing grid assets will remain on the system. Resource planning processes almost always seek LCBF solutions to identified *incremental* system needs. They focus almost exclusively on finding ways to satisfy load growth, though they do also seek to replace any capacity that is scheduled for retirement. But until recent years, planners have generally assumed as a shortcut that existing grid assets are part of the LCBF solution and will remain part of the system unless and until they are scheduled for retirement as a result of some separate evaluation. Because of this simplified approach, the possibility that existing assets could be replaced *before* their scheduled end of life by lower-cost solutions is not always examined as part of the utility's planning process. Wherever this kind of shortcut persists, BCA methods can readily be used to evaluate whether early retirement of specific power plants would reduce the revenue requirement (or, under a different cost test, increase net benefits).

Treating DERs differently from utility-scale assets. This is done in large part because it is easier to model utility-scale assets. For example, modeling the impact of adding a 1,000 MW utility-owned power plant at a specific location on the grid requires far less computational power than modeling hundreds of thousands of individual customer-owned solar photovoltaic systems rated at less than 10 kW each that are scattered all over the system. To make matters worse, some DERs pose their own modeling challenges because their impact on the system depends on day-to-day operational decisions made by customers, not by the utility. This is especially true for distributed energy storage solutions and electric vehicle charging but also true for demand response. Out of necessity, power system modelers make simplified assumptions about how those DERs will operate. They can model different scenarios with different assumptions, but the models cannot possibly compute every theoretical combination of assets and how they are operated to arrive at a true least cost solution. Instead, the most common approach is to assess likely scenarios for DER growth outside of the resource planning models, and then use the results of the exogenous DER assessments to modify the load forecast that goes into the planning process. This approach has a serious limitation, however, because there is no guarantee that utility-scale resources selected via the planning process will actually cost less than adding even more DERs than was determined exogenously. A detailed BCA of a specific DER proposal may find that the proposal reduces the revenue requirement below what the simplified modeling identified as the LCBF solution.

Timing differences can also cause these two techniques to lead to different answers even if BCAs are conducted using the UCT. Utility IRPs are huge undertakings; for that reason, most states require utilities to update them only every two or three years. Transmission plans and DSPs may be updated more or less frequently (usually more frequently) but are rarely completed on the same schedule as IRPs. In the intervals between different types of plans (for example, between the issuance of an IRP and the start of a DSP process) or the periods in between updates of a single type of plan, utilities or others may have reason to propose expenditures that were not included in the most recently issued plan. In those cases, it makes little sense to evaluate the proposed expenditures using the exact same data assumptions as the recent plan, if different and more accurate data are available today. For example, because energy storage costs have plummeted faster than expected, it would be unwise to assess a utility energy storage proposal today using data assumptions about storage costs from an IRP completed three years ago. A BCA might reveal that a storage project that was not included in the LCBF portfolio three years ago is cost-effective today even under a UCT.

Because BCA is used to evaluate specific proposed expenditures, rather than every possible solution to meeting a grid need, it is possible to look at costs and benefits associated with those proposed expenditures in much greater detail than is normally done with LCBF. This, by itself, can generate different answers from an LCBF evaluation even if the UCT is used. For example, the models used for IRP purposes might make little or no attempt to minimize costs for ancillary services, but with BCA the costs and benefits of a demand response program or energy storage system that is designed specifically to provide needed ancillary services can be assessed in exacting detail, perhaps revealing that those DERs can reduce the revenue requirement.

And that brings us to the final reason why BCA can lead to different (and better) decisions than total reliance on LCBF methods, even in jurisdictions that rely on the UCT. As we've already noted, most planning processes focus on only one portion of the electric power system: generation, transmission or distribution. To keep the analysis manageable, the LCBF approach described above identifies the least costly way of meeting identified needs *for that portion of the system*. But because BCA is only used to evaluate specific options, rather than all options, a more detailed examination of costs and benefits across all parts of the electric power system is possible. So, for example, one can imagine a hypothetical case where an IRP process finds that a new power plant is the least costly way to meet future needs for power generation. But a BCA might reveal that a distributed energy storage solution which costs more than the power plant (while providing equivalent contributions to resource adequacy) will reduce distribution system costs and, considering all parts of the power system, be cost-effective under a UCT.

For all these reasons, it is entirely possible that BCA techniques will reveal utility expenditures (for utility assets or for DER programs) that reduce the revenue requirement (i.e., pass the UCT) compared to the portfolio of assets identified in an IRP, transmission plan or DSP. If a different cost-effectiveness test is used, there is an even greater likelihood that some expenditures will be cost-effective because additional potential benefits will be quantified. This conclusion does not diminish the value of LCBF techniques; rather it underscores the usefulness of both methods in certain circumstances.

V. When Might BCA Be Used?

Utility regulators have historically used BCA techniques primarily to assess energy efficiency and demand response programs.[16] Almost every state is familiar with this practice. In the past decade, however, utilities and regulators have increasingly used BCA methods in other contexts, such as those shown in Table 2, to inform a broader set of regulatory decisions. The detailed reference report published as a companion to this issue brief provides insights into the circumstances or conditions under which BCA might be used in some of these proceedings to improve regulatory outcomes. The reference report includes links and further details regarding the specific state examples noted in Table 2. Armed with this information, regulators can decide whether they wish to expand the use of BCA methods in their own jurisdictions.

Table 2. Regulatory proceedings where BCA techniques are increasingly being used

Type of regulatory proceeding	Goal of BCA	State PUC examples cited in reference report
Customer-facing DER programs	Determine whether to implement a program and/or how to design the program	Energy efficiency: CO, MI, UT Demand response: CA, CO, IL, MI, PA, UT Building electrification: CO Distributed generation: PA, WI Distributed storage: CT, MA, MI
Distribution system infrastructure investments	Determine whether to make the investment	Advanced metering infrastructure: AR, CT, MA, MD, ME, NY, VT Electric vehicle charging infrastructure: CO, MI, NY Energy storage: MD Grid modernization: CA, HI, MI
Long-term plans (IRP, transmission and DSP) and procurement of nonwires alternatives	Determine optimal DER investment levels and contributions to preferred resource portfolio	Determining investment levels for energy efficiency and demand response: CA, ID, OR, UT, WA, WY Identifying locational net benefit opportunities: CA Evaluating nonwires alternatives to utility infrastructure: MI, MN, NV, NY, OR, RI
Rate cases/rate design	Determine the value of DER as basis or justification for compensation rates	AR, CA, DC, GA, HI, LA, ME, MN, MS, NV, NY, OR, SC, UT, VT
Performance-based regulation	Determine value of utility incentives	Energy efficiency programs: AR, AZ, MN, MO

[16] To be more precise, in nearly all cases a utility or another party conducts the BCA and then enters the results into the record of a utility commission proceeding.

VI. How Might BCA Be Used to Optimize Investment?

While recognizing that there is a long and rich tradition of papers, reference reports and regulatory decisions addressing the question of *how* to evaluate utility investments, we view the NSPM as the essential document for anyone interested in understanding how to apply BCA methods to DERs or almost any kind of utility investment. In addition, the same team that created the NSPM published a companion document in 2022 that provides more details on methods, tools and resources for conducting BCA studies.[17]

Rather than summarizing the content of the NSPM, in this issue brief we will instead focus on five crucial questions regulators must answer as they shape BCA policies for their jurisdictions. The answers to these questions can strongly influence the extent to which a BCA furthers the public interest and leads to better investment decisions. This issue brief cannot tell regulators the "right" answers to these questions, but we will suggest some factors for regulators to consider as they develop their own answers and, where possible, note some examples of commissions that are trying to tackle these issues.

1. In what proceedings will we use BCA methods?

BCA methods can point the way to smarter utility investment decisions, but a BCA can also be complex, costly and time consuming. State regulators can protect the public interest and the interests of ratepayers by encouraging or requiring parties to use state-of-the-art BCA methods when and where doing so is appropriate. The fundamental question for regulators will always be, perhaps ironically, whether the benefits of doing a BCA will exceed the costs. This will always be a judgment call, since the two variables in that equation can never be known until the BCA itself is completed. We suggest that regulators consider opening a proceeding or hosting a workshop to consider this specific question in the broadest sense — that is, to consider what types of proceedings are suitable for using BCAs. Or regulators can pose the question in specific dockets where BCA methods might be used and solicit responses from the parties.

Regulators in some states have hosted workshops with presentations from invited subject matter experts to explore the question of when and how to use BCAs in specific regulatory proceedings — for example, a DSP investigation in Illinois, a transportation electrification docket in Oregon, a distribution planning workgroup in Michigan and a grid modernization initiative in New Mexico.

2. Who will conduct BCAs?

Utilities will sometimes present regulators with a BCA they completed or a contractor completed on their behalf. But in other cases, the regulators themselves may come to appreciate that a BCA would be helpful in making decisions, and a key question then becomes, whom should they direct to do the work and who will oversee it? The answers

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[17] National Energy Screening Project. (2022). *Methods, tools and resources: A handbook for quantifying distributed energy resource impacts for benefit-cost analysis*. https://www.nationalenergyscreeningproject.org/resources/quantifying-impacts/

could involve a utility, a contractor, commission staff or another state agency. Furthermore, the PSC might consider ordering a utility to provide data and otherwise cooperate with a party to a proceeding that wishes to complete its own BCA and submit it into the record.

3. How will we engage stakeholders?

There is considerable variability among the states in how stakeholders have been allowed to participate in developing, contributing to or reviewing BCAs. In some states, the answer to this question has even varied across different types of proceedings.

Our research finds that it is standard practice to allow stakeholders to review and comment on filed BCA results before regulators make a final decision, but regulators need to also think about whether BCA results will be presented in a sufficiently detailed and transparent manner for stakeholders to meaningfully review them.

Some of the other key aspects of this decision revolve around whether stakeholders will be participants or spectators in or completely excluded from the following key steps that occur before a BCA is completed and results are filed at the PSC:

- Designing or deciding on the cost-effectiveness test(s) that will be used.
- Choosing scenarios, portfolios or test cases that will be evaluated.
- Selecting BCA input data sources or assumptions.

In several jurisdictions, task forces or working groups have been established that allow many parties to play an active role, as full participants, in energy efficiency potential studies, program plans and evaluations. To name just two examples, the Northwest Power and Conservation Council established the multiparty Regional Technical Forum (https://rtf.nwcouncil.org/) to help quantify the costs and benefits of energy efficiency measures. The results are used by utilities and regulators across a four-state region. And in 2013, the Arkansas PSC ordered the creation of an ongoing multistakeholder group that came to be called the Parties Working Collaboratively. Although these two examples apply only to energy efficiency programs, there is no reason why stakeholders could not or should not be proactively involved in decisions about how to conduct BCAs for other investment decisions.

4. Which cost-effectiveness test(s) will we use?

As we explained in Section III, the question of whether an investment is cost-effective depends on the perspective from which costs and benefits are tallied. Different tests evaluate cost-effectiveness from different perspectives. For the purposes of reviewing energy efficiency programs, most states have chosen to use one test as their primary test for making decisions, even though they often review BCA results from more than one perspective. However, many states have not decided on a primary cost test that applies to other DERs, let alone all DERs or all types of distribution system investments.

One of the most consequential decisions regulators must make for any proceeding in which they will request BCA results is to decide on a primary cost test. We believe that regulators will find no better source of guidance in making decisions about BCA policies than the NSPM. The manual offers regulators a set of principles that can guide their selection of a cost test and their decisions on many detailed questions about how to apply BCA methods. It also describes a clear five-step process that regulators can use to design their own tailor-made JST.

Reviewing the cost tests currently in use in any jurisdiction can be a significant undertaking, even more so if that is but the first step in changing the tests to be used or developing a JST. It is not something regulators should undertake casually. However, jurisdictions that are inconsistent in the tests they use for different DERs run the risk of allocating resources in suboptimal ways, spending too much on one type of DER and too little on another. The larger the scale and the faster the pace of investment, the greater the risk. Jurisdictions may also be evaluating resources in ways that are inconsistent with established environmental or social policies, which can interfere with or increase the cost of meeting those policy goals. Getting the cost tests "right" can help to address this problem. We suggest that each jurisdiction weigh the risks of making bad investment decisions against the cost of reviewing and updating the BCA tests they use.

Several states, in fact, have already embarked on designing their own JST for energy efficiency programs, following the recommended steps in the NSPM. The sponsors of the NSPM have published case studies describing efforts in Arkansas, Minnesota, New Hampshire and Rhode Island.[18] These case studies provide a good preview of what regulators in other states pursuing a JST might expect to happen. In addition, the reference report published as a companion to this issue brief cites examples from two states (California and New York) that have established a uniform BCA framework for all DERs and two examples of states (Maryland and Washington) that have open proceedings investigating a uniform BCA framework for all DERs.

We note that there are many challenging aspects of applying BCA methods beyond merely choosing (or designing) a cost test. These include questions about how to quantify and monetize DER impacts, especially difficult-to-quantify impacts like safety, resilience, energy security, equity and risk impacts. Selecting a discount rate to apply to future year benefits and costs is another difficult, controversial topic. Fortunately, the newly published companion document to the NSPM (*Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis)* offers fairly detailed guidance on how to address some of these questions.

Although it is helpful to use consistent BCA tests and methods for all types of resources, some states may find it impossible or impractical to revamp all their evaluation practices all at once. In those cases, incremental steps toward a consistent approach can be taken each time a relevant proceeding is adjudicated.

[18] National Efficiency Screening Project. (n.d.). *Application of NSPM — case studies*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/nspm-application-by-state/

5. How will we use BCA results to make decisions?

Although this issue brief encourages regulators to make greater use of BCA methods, we do not intend to suggest that the quantitative results of a BCA should bind the hands of decision-makers. Regulators have discretion in how they exercise their authority, including discretion over whether and how they will use BCA results to inform their decisions.

A variety of practices can be observed as one pores over the many examples of BCAs used by state regulators. We see cases where regulators have chosen to use BCA results in the following ways:

- As the determinative factor in preapproving investment decisions or allowing cost recovery for past decisions — for example, in approving a proposed utility investment in energy storage or advanced metering infrastructure.
- To establish investment budgets or ceiling prices for procurement — for example, energy efficiency program budgets.
- To design programs or retail rates — for example, in choosing an incentive level for demand response program participation or a compensation rate for energy exported by customers with solar photovoltaics.
- To set investment priorities — for example, in deciding which utility grid modernization investments to do first.
- To determine monetary incentives for a utility or program administrator operating under a performance-based regulatory regime.
- As supplemental information — for example, as one of many quantitative and qualitative factors considered when comparing potential utility investments or deciding if a particular utility investment is in the public interest.

VII. Conclusion

Least cost/best fit methods still have a significant role to play in making decisions about electric utility investments and probably always will. However, benefit-cost analysis methods can play a much bigger role in the power sector transformation we see happening today and can contribute to better decisions about distribution system investment.

Opportunities abound for using BCA in a wide variety of proceedings to improve investment outcomes, thereby maximizing net benefits (from an agreed perspective) rather than simply minimizing costs. In addition to their traditional use in planning and evaluating energy efficiency programs, BCA methods are increasingly used to evaluate other customer-facing DER programs, such as incentive programs for demand response, behind-the-meter energy storage and electric vehicles. BCA methods can also be applied to decisions about utility investments in infrastructure, either as a stand-alone proceeding, in a rate case or as part of a long-term planning process. And finally, for those DERs that can inject energy into the distribution system, state utility commissions have reviewed BCA results to inform decisions about net metering tariffs and other retail rate designs. Examples of all these uses of BCA are documented in detail in the reference report published as a companion to this issue brief.

Public utility commissions will play a large role in determining whether and when BCA methods will be used to evaluate investment options. They can also dictate whether utilities, commission staff or other parties will conduct the BCAs, whether stakeholders will be active or passive participants in the analysis, what costs tests and methods will be used and how the BCA results will be used when it is time to make investment decisions. None of this is easy, but in many cases the level of effort that is required to do a BCA can easily be justified because it supports and validates decisions that optimize benefits, avoid expensive mistakes and protect ratepayers and utility shareholders.

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