MI POWER GRID

Making the Most of Michigan's Energy Future

Benefit Cost Analysis

Electric Distribution Planning Reconvened Workgroup

U-20147

December 22, 2021

MPSC

Michigan Public Service Commission

Contents

Executive Summary

On October 17, 2019 the Michigan Public Service Commission (MPSC) launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating new technologies; and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. Stakeholder groups are formed and led by MPSC Staff. This report highlights the efforts of a reconvened stakeholder session to present additional information on Benefit Cost Analysis (BCA) methodologies following these three previous events: 1) previous workgroup session held on August 14, 2019, that addressed BCA, 2) the corresponding staff report that was submitted to the U-20147 docket on April 1, 2020, which included staff BCA recommendations, and 3) the Commission order in U-20147 on August 20, 2020 which addressed staff's recommendations.

The subject matter experts for this November 3, 2021 session were John Shenot, Regulatory Assistance Project (RAP); Julie Michals, e4TheFuture; Tim Woolf, Synapse Energy Economics; and Joe Eto, Lawrence Berkeley National Laboratory. John Shenot's presentation covered how other states use BCA in regulatory proceedings. Julie Michals addressed using a consistent BCA framework to inform utility investment decisions. Tim Woolf further explored BCA applications relevant to distribution planning. Danielle Sass Byrnett of the National Association of Regulatory Utility Commissioners (NARUC) led a panel that featured John Shenot, Julie Michals and Tim Woolf. The panel engaged in an extended discussion addressing BCA principles and applications. Joe Eto provided an update to the Interruption Cost Estimate (ICE) calculator.

The purpose of this reconvened workgroup was to further explore research and applications of BCA that have developed since the Commission issued their August 14, 2020 order in the U-20147 distribution planning docket, including a review of the National Standards Practice Manual (NSPM) for Benefit Cost Analysis of Distributed Energy Resources that was released in August of 2020. The value-added information provided at this workgroup session and the corresponding staff summary is intended to assist the Commission for their further consideration of BCA methodologies for utility electric distribution planning following the regulated utilities' 2021 filings of their distribution plans.

1. Introduction

Following the Staff report that was filed in the U-20147 docket on April 1, 2020 and the subsequent Commission order filed on August 20, 2020, the BCA topic remained of interest to the stakeholders in the MI Power Grid Electric Distribution Planning workgroup (Phase I- Electric Distribution Planning) as well as the MPSC. Staff assembled subject matter experts and scheduled this follow-up workgroup session held on November 3, 2021, to further address the parameters of BCA in relation to electric distribution grid investments. The session agenda, slide presentation, and recording of this session are available online at the webpage dedicated to Phase I - Electric Distribution Planning. The slide presentation is also attached to this report as Appendix A.

2. Presentation Summaries

2.1 How Other States Use BCA in Regulatory Proceedings

John Shenot is a Senior Advisor for RAP. He began by giving an overview of BCA. BCA estimates both the lifetime benefits and costs of a potential action in present dollars. If benefits exceed costs, the proposed contemplated action is "cost effective." Shenot emphasized that this is not necessarily as straight forward as it seems. Benefits and costs look different from different perspectives.

BCA is typically used in four different Public Service Commission proceedings: (1) ratepayer-funded distributed energy resources (DER) programs plans and evaluations, (2) rate cases/rate design, (3) grid modernization investments, and (4) long-range planning.

BCA techniques have not typically been used to evaluate the cost-effectiveness of traditional investment in utility-owned infrastructure. Instead, these investments are typically evaluated as part of a utility's planning process. Usually, the utility uses computer models to find its least cost solution to the identified needs.

Shenot explained the five traditional BCA tests: the Utility Cost test, the Total Resource Cost test, the Societal Cost test, the Participant Cost test, and the Rate Impact Measure test.

He discussed BCA analysis in ratepayer funded DER program plans and evaluations. He also gave robust examples from cases in Wisconsin (energy efficiency), Pennsylvania (demand response), and Oregon (electric vehicles).

Subsequently, Shenot turned his focus to rate cases and rate design. He highlighted an ICF study on net metering and distributed solar for the U.S. Department of Energy. This report used BCA to evaluate whether net metering programs achieved its stated goals. The report utilized all five BCA tests. Each test offered a different analysis and different results.

Shenot examined grid modernization investments. He noted this is another area where BCA can be useful. He gave illustrative examples from the Arkansas (AMI programs), Hawaii (grid modernization) Maryland (storage), and Texas (undergrounding) commissions.

Lastly, he talked about using BCA with long-range planning. These methods can be integrated into utility planning processes. He cited Pacificorp's DER supply example that the utility has used in multiple jurisdictions. Next, he walked the stakeholders through a BCA of non-wires alternative from the New York Commission.

Shenot concluded his presentation with four main BCA takeaways. First, BCAs yield different answers than least cost modeling. Second, BCAs are commonly used to evaluate utility programs offered to customers. Third, they are occasionally used to evaluate rate design or utility infrastructure investments and may not be the best tool in all cases. Lastly, BCAs can supplement a least-cost planning best-fit processes or can be integrated into the process.

2.2 Using a Consistent BCA Framework to Inform Utility Investment Decisions

Julie Michals from E4TheFuture gave a presentation on the National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources. (The 2020 NSPM for DERs incorporates and expands upon the 2017 National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources (NSPM for EE)).

The NSPM provides guidance to help states 1) refine, improve, or develop a primary test for using the foundational principles to guide the BCA process, 2) understand the full range of utility system impacts, 3) understand the full range of potential non-utility system impacts, and 4) understand key factors that affect whether an impact is likely to be a net benefit of cost for a specific DER or combination of DERs.

The NSPM is not a document that 1) prescribes any specific cost effectiveness test or favor any cost effectiveness test, 2) advocates the inclusion of any specific non-utility system impacts, or 3) adheres to or restricts theoretical definitions of traditional tests.

Principles of the NSPM that are economically sound and policy neutral include ensuring that DERs are compared with other energy resources and treated consistently for BCA, aligns with jurisdiction's policy goals, ensures symmetry across costs and benefits, accounts for all relevant material impacts even if they are hard to quantify, conducts a forward looking long term analysis that captures incremental impacts of DER investments, avoids double counting, ensures transparency in presenting the benefit cost analysis and results for all stakeholders included, and conducts BCA separate from rate impact analyses because they answer different questions.

Having consistency in BCA across DERs is important because it ensures there is not under or over investing resulting in a bias toward one resource or another and helps streamline the process. A siloed approach to valuing different DERs can be complex and overwhelming for everyone involved. Having consistency in BCA across DERs also allows for comparison and prioritizing of DER investments to find out which should be implemented and which should be rejected, policy goals met by investing in DERs, and how to ensure customers are not paying too much to achieve these policy goals.

Developing a primary jurisdiction specific test requires five steps. Step one is articulating applicable policy goals. Step two is including all utility system impacts. Step three is dividing which non-utility system impacts to include. Step four is ensuring that benefits and costs are properly addressed. Step five is establishing comprehensive, transparent documentation.

Secondary cost effectiveness tests can also be useful. While the primary test informs about whether to find or support DERs, secondary tests can help to inform decisions on how to prioritize DERs, inform decisions regarding marginally non-and/or cost effective DERs, and encourage consistency across DER types.

2.3 BCA Applications Relevant to Distribution Planning

Tim Woolf is Vice President at Synapse Energy Economics. His presentation focused on the role of BCA in distribution planning. Woolf identified three key areas for BCA analysis within distribution planning: reliability and resilience, affordability, and energy equity.

Woolf provided a high-level overview of the role of BCAs in different regulatory settings. He discussed how BCA could be used in the analysis of energy efficiency, demand response, distributed generation, storage, electric vehicles, non-wire alternatives, and DERs. He observed that distribution planning typically happens outside of a traditional rate case. Cost recovery should be informed by and be consistent with these distribution planning activities.

Woolf argued strongly that the same principles and concepts used to develop BCA tests for DERs should be used to develop the BCA tests for distributed planning. He recommends using the same primary test (i.e., Jurisdiction Specific Test). Failure to do so may result in uneconomic outcomes.

Like Shenot, Woolf distinguished BCA from least-cost best-fit. The critical difference is that the latter does not require any estimate of benefits. It is presumed that the investment is needed. A BCA provides much more information. It provides certainty as to whether benefits exceed costs. Woolf recommends to only use least-cost best-fit when it is necessary. Lastly, he noted regardless of which approach is used, non-monetized benefits should be accounted for as much as possible and provide as much quantitative data as possible. Always attempt to define the benefits in such a way that they can be monetized. He recommends using quantitative methods to address non-monetized benefits.

Woolf discussed reliability and resilience. He began by defining terms. He highlighted the key distinction between the concepts is that reliability pertains to routine events while resilience pertains to extraordinary events. Reliability metrics need to be clearly defined. Regulators need to be thoughtful in creating methods to determine both the direct and indirect monetary value of improved resilience.

Affordability involves both the costs on the utility system and the cost impacts on the customers. Woolf noted that BCA can indicate the lowest utility system costs and can be used to assess affordability. However, it may not account for other policy goals. It is also important to use different metrics to assess bill impacts (i.e., dollars/month, by customer type).

Equity is always an important planning criterion. Affordably is different for different customers. Woolf suggested four key equity questions for regulators to consider. First, is this the lowest cost plan for the desired outcomes? Second, what are the long-term bill impacts of the plan? Third, does the plan provide equitable reliability and resilience benefits? Lastly, does the plan provide equitable access to DERs?

2.4 BCA Issues Specific to Michigan

The stakeholder session featured a panel on BCA issues specific to Michigan. Danielle Sass Byrnett, Director of the Center for Partnerships & Innovation at NARUC moderated the panel. Julie Michals, John Shenot, and Tim Woolf were the panelists.

Sass Byrnett asked a very relevant question about quantifying typically qualitative metrics and asked panelists to provide some examples of metrics that are used to assess benefits that you wouldn't otherwise use to quantify benefits. Woolf responded that reliability metrics such as customer outages and value of lost load are becoming increasingly monetized. Over time, you move from a lack of information to a metric to quantitative value such as customer engagement and customer satisfaction. Shenot agreed and added the example of assumed value to monetize avoided greenhouse gas emissions. Historically it was rare to see monetized public health benefits. The data just wasn't historically available. However, a year or two ago, the EPA started making estimates of public health benefits. Now you can monetize a benefit that couldn't happen five years ago. Michals added another example of economic development impacts and job creation. There are different methods to quantify benefits and GDP is important to have as a quantitative impact.

The panel engaged in an extended conversation about the process for designing jurisdiction specific tests. Sass Byrnett asked the panelists "What makes some of these tests unique?". Woolf discussed the test designed in New Hampshire which only focused on energy efficiency. In New Hampshire, there was a balance of stakeholders that struggled with host/customer impacts and whether to include or exclude them. The group decided to not include non-energy impacts such as host customer impacts. They initially could not decide whether to include environmental impacts. They decided to not include environmental impacts in the primary test but did include them in a secondary test. This example of New Hampshire is significant because it emphasizes the importance of a robust, transparent discussion among stakeholders. It also shows that when choosing to exclude benefits, they also excluded costs. Shenot stated that most states nominally use one of the traditional tests but then maybe add another component such as avoided greenhouse gas emissions.

There are many ways to customize jurisdiction specific tests, and more states have done so than what the maps in the presentations include. Michals spoke about Arkansas, a state that is reviewing different principles and checking with alignment with energy efficiency. Arkansas did not adopt all recommendations where there was misalignment, but one unique aspect was there was not a lot of transparency from utilities and utility system impacts. Some corrections were necessary to help build transparency, symmetry, and alignment of policies. Michals also spoke about Maryland. There was a final report by joint utilities who responded to a commission order to build a BCA on EV proposals. The NSPM was applied, and Maryland is seeing alignment with policies and separation of BCA and Rate Impact Analysis (RIA). Maryland also looked at all impact factors and use cases and changes were made to better understand different impact factors.

Sass Byrnett asked the panelists how long it takes to create a jurisdiction specific test. Woolf stated that it depends on the state. In some cases, they are just looking to answer some questions and the NSPM refines what they are doing. It also depends on how much stakeholder involvement they want. Michals agreed. It really varies by the jurisdiction and how much research and learning they want to do. New Hampshire took five months. Minnesota is having to rethink some policy changes so it might be more than one yar. Puerto Rico had no policies to start with so they will finish in a couple of months.

Lastly, Sass Byrnett asked if there are utilities that have proceeded with using BCA without being ordered by their Commission. Shenot responded that in most jurisdictions, regulators have developed a policy that tells the utilities how to do things, but there is a small, rapidly growing list of examples where BCA is explicitly used for decisions. There is not a policy framework for these states, so what you see is utilities trying to put their best foot forward with what will sway the Commission and other parties. They sometimes pick the test itself to try to make their preferred investments as good as possible. Without a framework, it is often a hodge podge of using one test for one investment and another test for another investment.

2.5 Interruption Cost Estimate (ICE) Calculator

The last presentation of the stakeholder session was given by Joe Eto, Senior Advisor, Lawrence Berkeley National Laboratory, on the Interruption Cost Estimate (ICE) Calculator. Customer costs of power interruptions are of increasing importance for identifying and prioritizing cost-effective utility investments to improve reliability and resilience. The ICE Calculator is the leading and only available tool for estimating the customer cost impacts of power interruptions. It is used to support internal utility reliability planning activities, provide a basis for discussing utility reliability investments with regulators, and assess the economic impact of past power outages. The ICE Calculator is based on more than a hundred thousand utility sponsored surveys exploring the costs customers incur when the lights go out.

There are some challenges and limitations to the ICE Calculator. The currently used surveys are old and outdated. The surveys are from 1980-1990 and represent a time when many people did not work at home. Not all utilities or regions of the country are represented by the surveys. The surveys are designed around shorter duration interruptions and their use is not recommended for interruptions lasting longer than 24 hours.

There is a plan to update and upgrade the ICE Calculator at the beginning of next year. It would include the development of a consistent set of short duration, customer interruption cost survey questions including some to understand customer behavior during widespread, longer duration interruptions. It would coordinate the administration of surveys to ensure the results are statistically representative of all US regions and customer classes. It would also include new information and improvements to design and performance. Sponsoring utilities' responsibilities in the update is to provide funding, support survey administration and sampling of customers, and provide feedback on ICE Calculator improvements to Berkeley Lab.

3. Conclusion

This workgroup session provided additional information regarding BCA methodologies and applications elsewhere throughout the United States. The presentations and stakeholder discussion that took place during this workgroup session represent additional contributions to the body of knowledge about the role of BCA with varying utility investments.

Michigan's three largest utility companies, DTE, Consumers Energy and Indiana Michigan Power Company, have recently submitted their second round of electric distribution plans in the U-20147 docket. The electric distribution planning process is ongoing at the MPSC. Further Commission action addressing suggested or required BCA methodologies for electric distribution investments is undetermined at this time. Staff would like to note that the U-20147 docket remains open for any additional stakeholder comments addressing BCA or other distribution planning issues.

Appendix A

Making the Most of Michigan's Energy Future

MI Power Grid: Electric Distribution Planning Reconvened Workgroup Meeting: Distribution Planning Benefit Cost Analysis

November 3, 2021

1:00PM – 4:00 PM (Eastern)

Agenda

Agenda Items		
1:00pm 5 min	Welcome & Opening Statements	Danielle Rogers, MPSC Staff
1:05pm 5 min	Benefit Cost Analysis Recap	Patrick Hudson, MPSC Staff
1:10pm 30 min	How Other States Use BCA in Regulatory Proceedings	John Shenot, RAP
1:40pm 25 min	Using a Consistent BCA Framework to Inform Utility Investment Decisions	Julie Michals, E4 the Future
2:05pm 5 min	Break	
2:10pm 25 min	BCA Applications Relevant to Distribution Planning	Tim Woolf, Synapse Energy Economics
2:35pm 50 min	Panel: BCA Issues Specific to Michigan	Moderator: Danielle Sass Byrnett, NARUC Panelists: Julie Michals, E4 the Future John Shenot, RAP Tim Woolf, Synapse Energy Economics
3:25pm 30 min	Interruption Cost Estimate (ICE) Calculator	Joe Eto, Lawrence Berkeley National Laboratory
3:55pm 5 min	Closing Statements	Patrick Hudson, MPSC Staff
4:00pm	Adjourn	

MI POWER GRID

Making the Most of Michigan's Energy Future

Reconvened Workgroup Meeting: Distribution Planning Benefit Cost Analysis

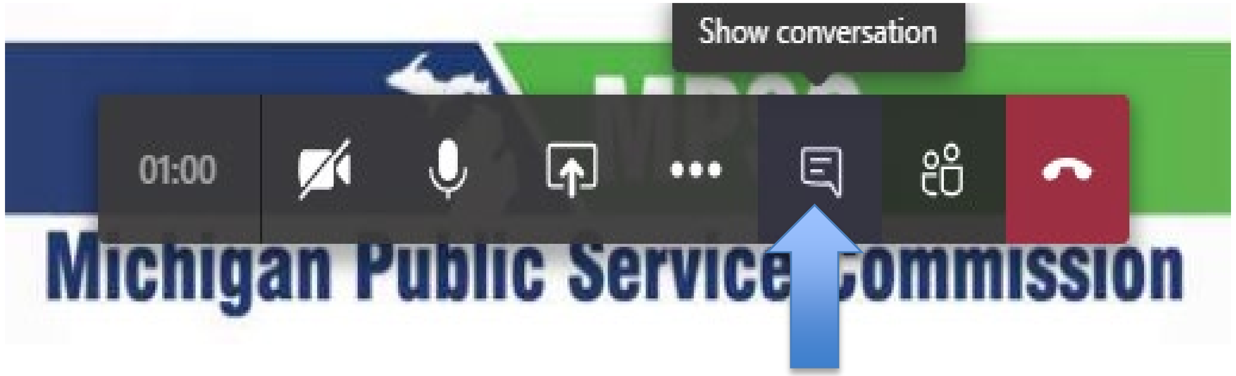
Housekeeping

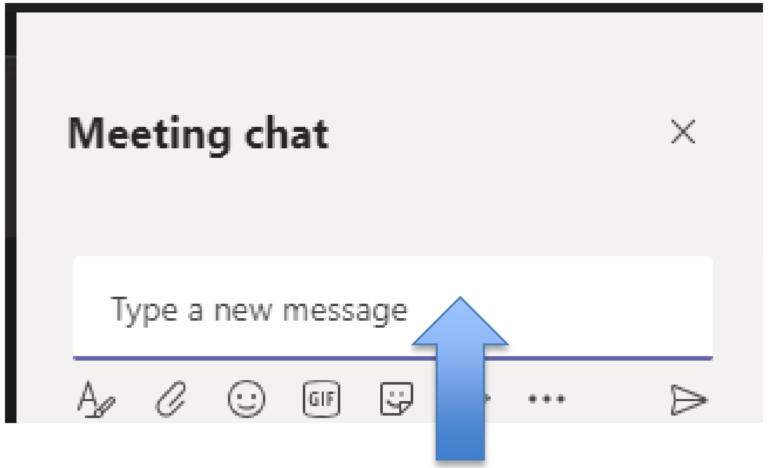
Danielle Rogers
Smart Grid
Michigan Public Service Commission

November 3, 2021

Housekeeping

- This meeting is being recorded
- Recording and slides posted on [workgroup website](#) in about a week
- All audience members will be muted
- Please type questions into the chat box
    - To access chat box:





- Staff will ask chat box questions during Q&A

Housekeeping, cont.

- During the meeting, if clarification of your question is needed, we will ask you to unmute.
  - To unmute:
    - Phone: Press *6
    - Teams: Click mic button
  - Please mute yourself again after your clarification.
- Chat box may note when audience members enter/exit
  - These notices are automatic
- If Teams via web browser is not working, try a different web browser.
  - All work except Safari

MI POWER GRID

Making the Most of Michigan's Energy Future

Reconvened Workgroup Meeting:

Distribution Planning Benefit Cost Analysis

Benefit Cost Analysis Recap

Patrick Hudson
Manager of the Smart Grid Section
Michigan Public Service Commission

November 3, 2021

Benefit Cost Analysis Recap

- June 27, 2019 → Nov. 19, 2019, the Electric Distribution Planning Workgroup met five times
- Part one of the August 14 session - explored Benefit Cost Analysis for distribution investments (Tim Woolf/Synapse Energy Economics, Paul Alvarez & Dennis Stephens/ABATE, Ryan Katofsky/AEE)
- September 18 session – explored resiliency and how it is valued (Joe Eto/LBNL)
- April 1, 2020, staff submitted a report to the U-20147 docket with summaries of the stakeholder process and recommendations, including BCA recommendations
- August 20, 2020, the Commission released an order addressing distribution planning going forward
- The Commission recognized the importance of BCA and suggested the conversation be continued after utility distribution plans were filed in 2021

Benefit Cost Analysis Recap

This all lead to today's further discussion:

- Overviews of BCA activity elsewhere in other states
- BCA methodologies
- The National Standards Practice Manual and associated cost tests
- The Interruption Cost Estimate (ICE) Calculator update (estimating interruption costs and/or the benefits associated with reliability improvements)

How Other States Use BCA in Regulatory Proceedings

John Shenot

Senior Advisor

Regulatory Assistance Project

3 November 2021

How Other States Use Benefit-Cost Analysis (BCA) in Regulatory Proceedings

MI Power Grid: Electric Distribution Planning Benefit Cost Analysis Session

Michigan Public Service Commission

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Outline

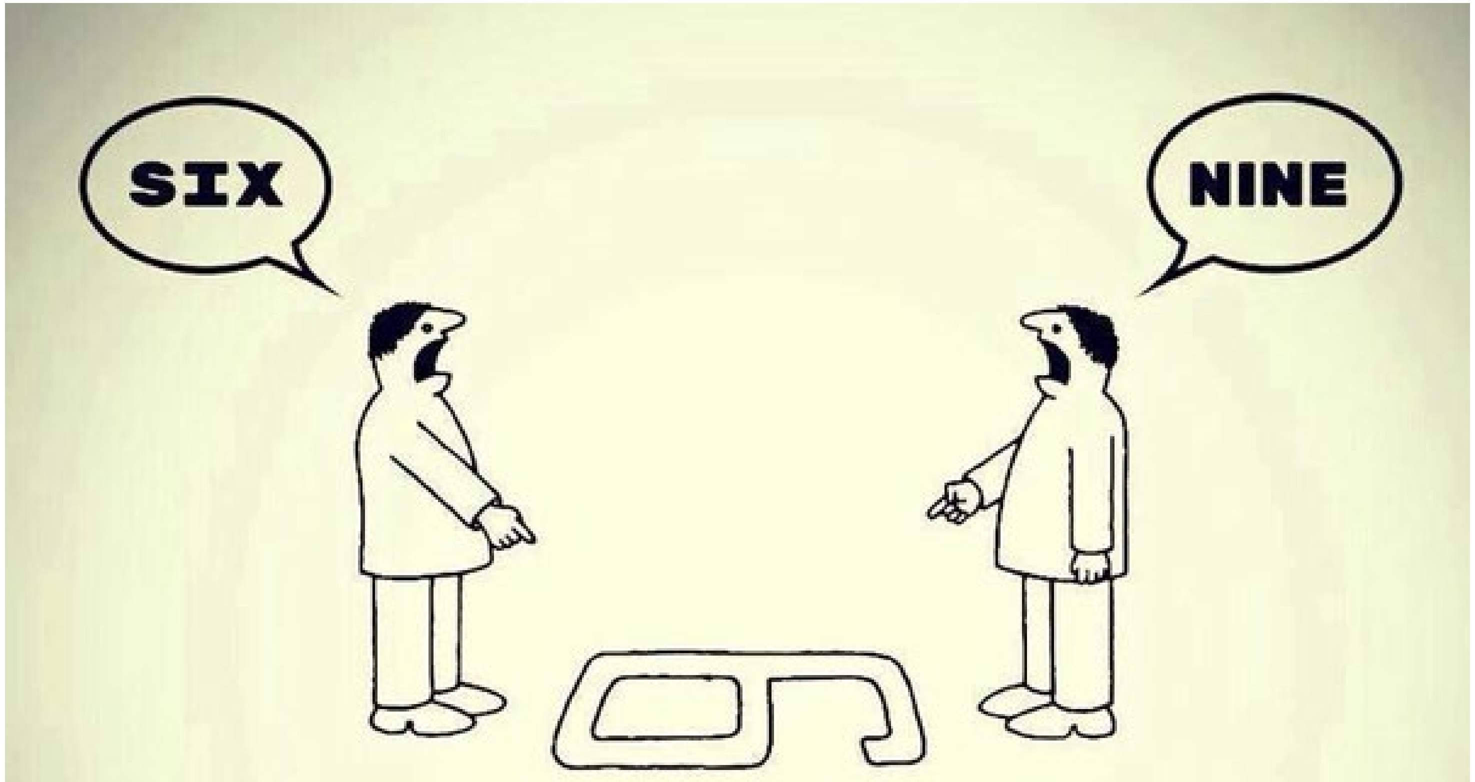
- BCA vs. Least-Cost Planning
- Proceedings where BCA is sometimes used:
    - Ratepayer-funded DER program plans and evaluations
    - Rate cases/rate design
    - Grid modernization investments
    - Long-range planning

1 BCA vs. Least-Cost Planning

BCA Basics

- Estimate lifetime costs of a potential action in present dollars
- Estimate lifetime benefits in present dollars
  - *Avoided cost = benefit*
- If benefits exceed costs, the contemplated action is “cost-effective”

Benefits and Costs Look Different from Different Perspectives

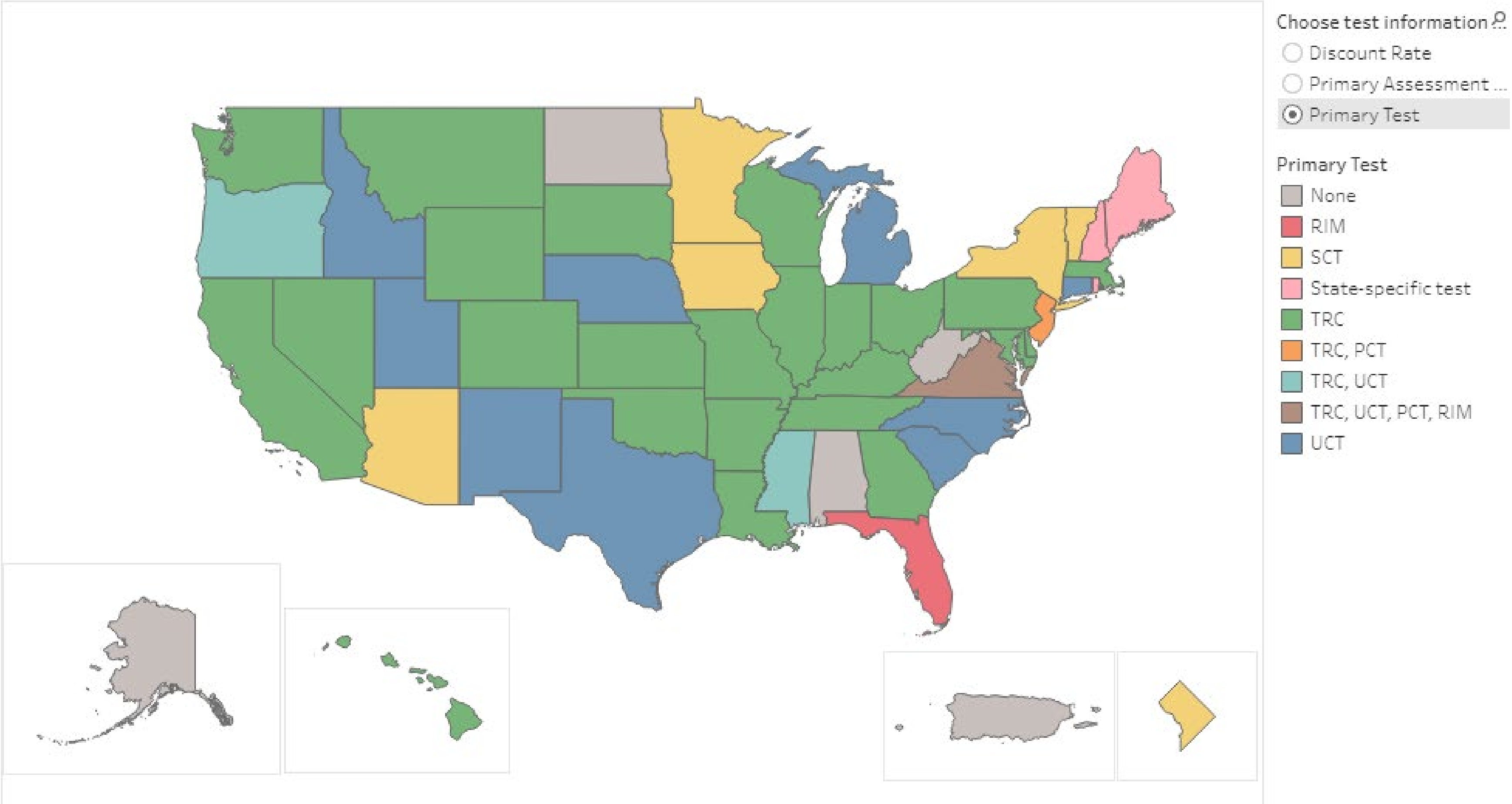


Traditional BCA Tests

Test	Perspective	Key Question Answered	Impacts Accounted For
Utility Cost Test (UCT)	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total Resource Cost (TRC)	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 (SCT)	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Participant Cost Test (PCT)	Customers who participate in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers who participate in the program
Rate Impact Measure (RIM)	Impacts on rates paid by 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

Source: National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, August 2020.

Primary Test for EE BCAs



Source: NESP, [Database of Screening Practices](), October 2021.

Least-Cost Planning

- BCA techniques have not typically been used to evaluate the cost-effectiveness of “traditional” investments in utility-owned infrastructure
- Instead, these investments are usually evaluated as part of a utility planning process where computer models are used to find the utility’s “least cost/best fit (LCBF)” solution to identified needs

2 Ratepayer-funded DER program plans and evaluations

EE BCA Example: Wisconsin

Table 26. CY 2020 Costs, Benefits, and Modified Total Resource Cost Test Results by Channel

	Residential	Nonresidential	Midstream	Renewables	Total
Administrative Costs	$1,292,223	$1,422,713	$9,657	$64,144	$2,788,738
Delivery Costs	$11,563,550	$17,745,763	$525,541	$709,320	$30,544,175
Incremental Measure Costs	$47,796,116	$158,148,925	$2,118,513	$42,957,092	$251,020,645
Total TRC Costs	**$60,651,889**	**$177,317,401**	**$2,653,712**	**$43,730,556**	**$284,353,558**
Electric Benefits	$71,967,357	$274,243,541	$684,267	$46,565,622	$393,460,787
Gas Benefits	$20,599,359	$103,887,844	$2,463,121	$0	$126,950,324
Emissions Benefits	$22,299,686	$85,800,515	$520,240	$7,844,515	$116,464,956
T&D Benefits	$10,443,511	$44,043,325	$178,562	$0	$54,665,398
Total TRC Benefits	**$125,309,914**	**$507,975,225**	**$3,846,189**	**$54,410,137**	**$691,541,465**
TRC Benefits Minus Costs	**$64,658,025**	**$330,657,824**	**$1,192,478**	**$10,679,580**	**$407,187,907**
TRC Benefit/Cost Ratio without T&D Benefits[a]	**1.89**	**2.62**	**1.38**	**1.24**	**2.24**
TRC Benefit/Cost Ratio with T&D Benefits[a]	**2.07**	**2.86**	**1.45**	**1.24**	**2.43**

Source: Cadmus, Focus on Energy Calendar Year 2020 Evaluation Report, May 2021

DR Example: Pennsylvania

Table 8. Summary of Demand Response Program Finances–Gross Verified

Row #	Cost Category	PYTD ($1,000)		P3TD ($1,000) [6]	
1	EDC Incentives to Participants	$980		$910	
2	EDC Incentives to Trade Allies	-		-	
3	Participant Costs (net of incentives/rebates paid by utilities)	($245)		($228)	
4	**Incremental Measure Costs (Sum of rows 1 through 3) [1]**	**$735**		**$683**	
		EDC	**CSP**	**EDC**	**CSP**
5	Design & Development [2]	-	-	-	-
6	Administration, Management, and Technical Assistance [3]	$39	-	$184	-
7	Marketing [4]	-	-	-	-
8	Program Delivery [5]	-	$267	-	$746
9	EDC Evaluation Costs	-		-	
10	SWE Audit Costs	-		-	
11 [6]	**Program Overhead Costs (Sum of rows 5 through 10) [1], [6]**	$305		$931	
12	NPV of increases in costs of natural gas (or other fuels) for fuel switching programs	-		-	
13	**Total NPV TRC Costs (Net present value of sum of rows 4, 11, and 12) [1], [7]**	**$1,040**		**$1,613**	
14	Total NPV Lifetime Electric Energy Benefits				
15	Total NPV Lifetime Electric Capacity Benefits	$6,188		$5,749	
16	Total NPV Lifetime Operation and Maintenance (O&M) Benefits	-		-	
17	Total NPV Lifetime Non-Electric Benefits (Fossil Fuel, Water)	-		-	
18	**Total NPV TRC Benefits [8] (Sum of rows 14 through 17) [8], [1]**	**$6,188**		**$5,749**	
19	**TRC Benefit-Cost Ratio [9]**	**5.95**		**3.56**	

Source: Cadmus, PPL Electric Utilities Demand Response Program Annual Evaluation, January 2018.

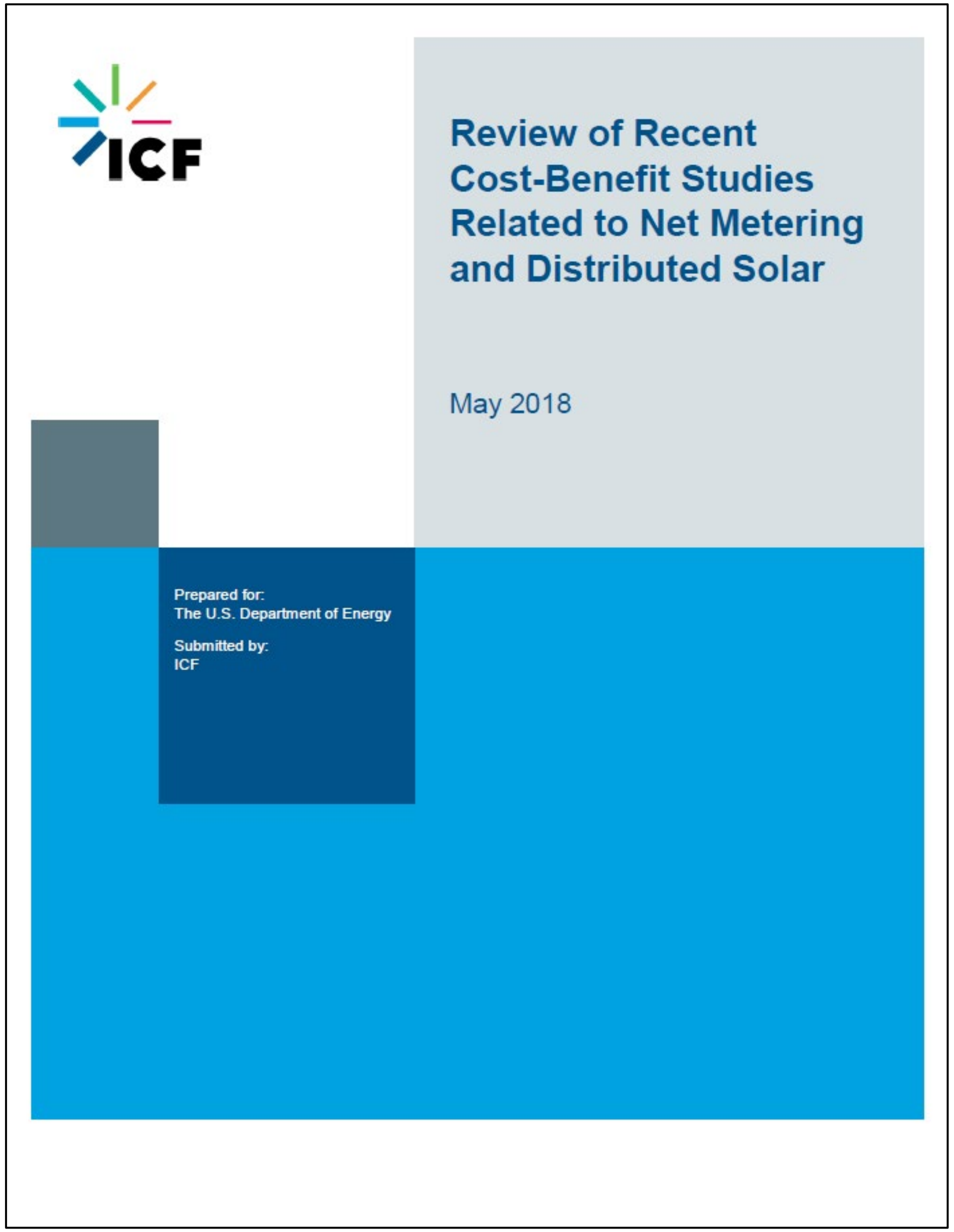
EV Example: Oregon

Table 12 Blended Cost/Benefit Ratio Based on Combined Pilot Program Components (Residential EV Charging)

RIM SUMMARY - NPV ($000S)	EV	DR	Total	%
Market Participation Revenue	-	-	-	0%
Avoided Cost of Supply	-	2,724	2,724	29%
Revenue Gain from Increased Sales	6,697	-	6,697	71%
Benefits	**6,697**	**2,724**	**9,421**	**100%**
Administrative Costs	2,226	1,951	4,177	31%
Capital Costs to Utility	497	-	497	4%
Incentives Paid	1,590	402	1,993	15%
Increased Supply Costs	6,639	-	6,639	50%
Costs	**10,953**	**2,353**	**13,306**	**100%**
Benefit/Cost Ratio	**0.61**	**1.16**	**0.71**	

Source: PGE, UM 1811 Transportation Electrification Compliance Filing, February 2019.

3 Rate cases/rate design



ICF

Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar

May 2018

Prepared for:
The U.S. Department of Energy

Submitted by:
ICF

Source: ICF, May 2018.

Studies Reviewed by ICF

State	Year	Study Sponsor	Prepared by
Arkansas	2017	Sierra Club	Crossborder Energy
District of Columbia	2017	Office of the People's Counsel	Synapse Energy Economics
Georgia	2017	Southern Company	Southern Company
California	2016	California Public Utility Commission (CPUC)	CPUC/Energy and Environmental Economics (E3)
Nevada	2016	State of Nevada Public Utilities Commission	E3
New York	2016	New York Public Service Commission (PSC)	NY Department of Public Service (DPS) Staff
Hawaii	2015	Interstate Renewable Energy Council	Clean Power Research
Louisiana	2015	Louisiana Public Service Commission	Acadian Consulting Group
Maine	2015	Maine Public Utility Commission	Clean Power Research
Oregon	2015	Portland General Electric	Clean Power Research
South Carolina	2015	South Carolina Office of Regulatory Staff	E3
Minnesota	2014	Minnesota Department of Commerce	Clean Power Research
Mississippi	2014	Public Service Commission of Mississippi	Synapse Energy Economics
Utah	2014	Utah Clean Energy	Clean Power Research
Vermont	2014	Public Service Department (PSD) Staff	VT PSD

Study Types

Type of Study	Number Reviewed	Description of Study Type	States/Prepared by
NEM Cost-Benefit Analysis	6	Evaluate costs and benefits of a NEM program; study whether NEM is creating a cost-shift to non-participating ratepayers.	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	7	Discuss the impacts of NEM and consider options for reforming or realigning rates with the net impacts of distributed solar in ways that go beyond net metering.	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	2	Reflect the elements of regulatory activities that look at VOS as part of a more precise approach within a framework that can be applied to other DERs.	▪ California LNBA (CPUC) ▪ New York BCA (Department of Public Service Staff)

BCA Tests Used

			Cost-Effectiveness Test				
State	Year	Prepared by	PCT	UCT	RIM	TRC	SCT
Arkansas	2017	Crossborder	√	√	√	√	√
District of Columbia	2017	Synapse		√			√
Georgia	2017	Southern Company					
California	2016	CPUC	√		√		
Nevada	2016	E3	√	√	√	√	√
New York	2016	NY DPS		√	√		√
Hawaii	2015	CPR					
Louisiana	2015	Acadian					
Maine	2015	CPR					
Oregon	2015	CPR					
South Carolina	2015	E3			√		
Minnesota	2014	CPR					
Mississippi	2014	Synapse	√			√	
Utah	2014	CPR					
Vermont	2014	PSD					

4 Grid modernization investments

AMI Example: Arkansas

Summary of Cost/Benefit Analysis

		Nominal ($M)	PV ($M, 2016)
	Quantified Operational Benefits		
1	Routine Meter Reading	$156	$94
2	Meter Services	$103	$62
3	Reduced Customer Receivables Write-offs	$11	$7
4	**Total Quantified Operational Benefits**	$270	$162
	Quantified Other Benefits		
5	Consumption Reduction	$303	$180
6	Peak Capacity Reduction	$145	$85
7	Unaccounted For Energy Reduction	$123	$72
8	Elimination of Meter Reading Equipment	$6	$3
9	**Total Quantified Other Benefits**	$577	$340
10	**Total AMI Quantified Benefits**	$847	$502

	AMI lifetime costs to customers[4]	**Nominal ($M)**	**PV ($M, 2016)**
11	Depreciation & Amortization	$209	$133
12	Return on Rate Base	$100	$70
13	AMI O&M Costs	$96	$59
14	Property Tax	$11	$8
15	**Total AMI Costs**	$415	$270
16	**Net AMI Benefit**	**$431**	**$232**

Source: Testimony in Arkansas PSC Docket 16-060-U, September 2016.

Smart Grid Example: California

TABLE 1 Estimated Costs and Benefits of Distribution Project Pilots (Costs in $ millions)			
Pilot	Cost of Pilot	Cost of Full Deployment[98]	Benefits at Full Deployment[99]
Line Sensors	$16.7	$98 – $131	$35.9
Volt/VAR	$38.4	$200 – $276	$536 - $1,070
Detect & Locate	$12.9	$74 - $103	$51.3 – $62.7
Totals	$68.0	$372 - $410	$611.2 - $1,132.7

Source: California PUC Decision 13-03-032, 2013.

Storage Example: Maryland

Staff Benefit vs Cost Analysis (High Benefits) - 15 Years of Benefits

	BGE		DPL		Pepco		PE	
	Chesapeake Beach	Fairhaven Substation	Elk Neck	Ocean City	National Harbor	Montgomery County	Town Hill	Little Orleans
Environmental & Public Health								
Air Emissions Reduction	$ (0.4)	$ (1.0)	$ 0.0	$ 0.6	$ 0.6	$ 0.6	$ (1.1)	$ (0.7)
Public Health Benefits	$ (1.9)	$ (5.0)	$ (2.0)	$ (2.2)	$ (2.1)	$ (2.1)	$ (12.5)	$ (6.7)
Distribution Grid Value								
Avoided Distribution Cost	$ 2,019	$ 5,383			$ 3,434	$ 2,662	$ 1,110	$ 792
Optionality	$ 1,219	$ 840			$ -			
Value of Avoided Outages							$ -	$ -
Peak Demand Reductions - Capacity & Energy								
Energy Conservation During Time of Peak	$ 1	$ 3	$ 2	$ 5	$ 5	$ 5	$ 102	$ 43
Peak Shaving	$ -	$ -	$ 502	$ 1,005	$ 886	$ 886	$ 968	$ 415
PJM Market								
Energy Arbitrage			$ 82	$ 200	$ 422			
Regulation		$ 1,692	$ 497	$ 1,250				$ 25
Reserves								$ 136
Benefit Vs Cost								
Total Benefit	$ 3,237	$ 7,912	$ 1,082	$ 2,459	$ 4,746	$ 3,551	$ 2,168	$ 1,405
Total Cost	$ 2,298	$ 10,952	$ 3,745	$ 5,959	$ 4,842	$ 2,471	$ 4,687	$ 2,882
Benefit to Cost	1.41	0.72	0.29	0.41	0.98	1.44	0.46	0.49

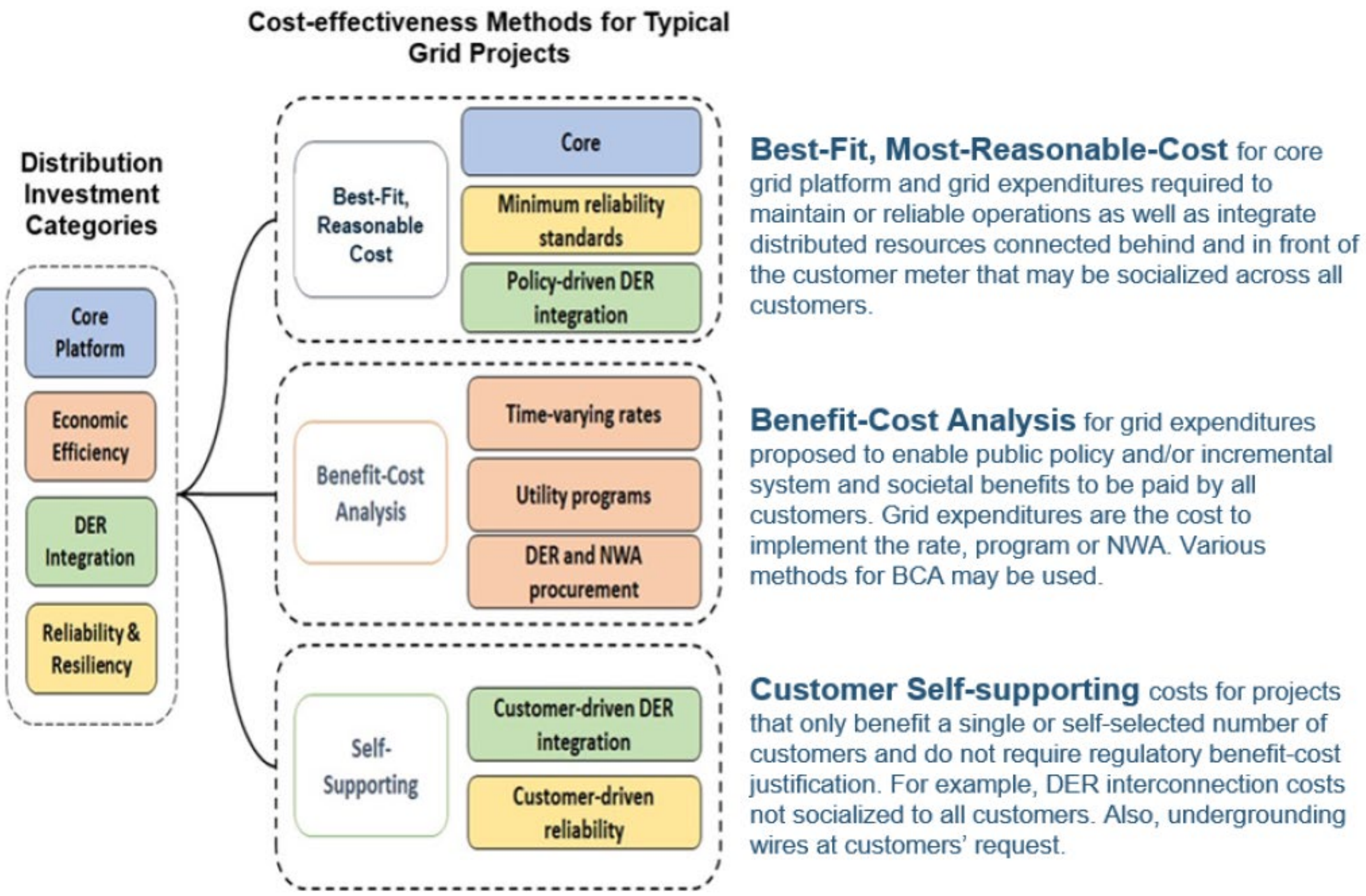
Source: Testimony in Maryland PSC Case 9619, June 2020.

Undergrounding Example: Texas

Impact Category	Undergrounding	Status Quo	Net Cost ($billions)
Environmental restoration	$2.8	$1.0	$1.8
Health & safety	$0.56	$0.31	$0.2
Lifecycle costs	$52.3	$26.1	$26.3
Total net costs (Undergrounding)			$28.3
Impact Category	**Undergrounding**	**Status Quo**	**Net Benefit ($billions)**
Interruption cost	$182.7	$188.4	$5.8
Avoided aesthetic costs	$12.1	$10.6	$1.5
Total net benefits (Undergrounding)			$7.3
Net Private Loss (Undergrounding)			
Net private loss (billions of $2012)			**-$21.0**
Benefit-cost ratio			**0.3**

Source: Peter H. Larsen, A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines, October 2016.

Is BCA the Right Tool?



Source: US DOE, *Modern Distribution Grid: Strategy and Implementation Planning Guidebook (Volume IV)*, June 2020.

Example: Hawaiian Electric Companies (HECO)

- Proposed a grid modernization strategy (GMS) in 2017 and proposed to use different evaluation techniques depending on the purpose of each investment:
  - LCBF for investments necessary to satisfy service quality, safety, and state policy requirements
  - BCA for investments that were not required but would yield net benefits to customers

Hawaii PUC response

- PUC conditionally approved the GMS in 2018:
  - Didn't comment on the proposed evaluation techniques
  - Directed the utility to file separate applications to implement the GMS and provide more details about costs and benefits in those applications

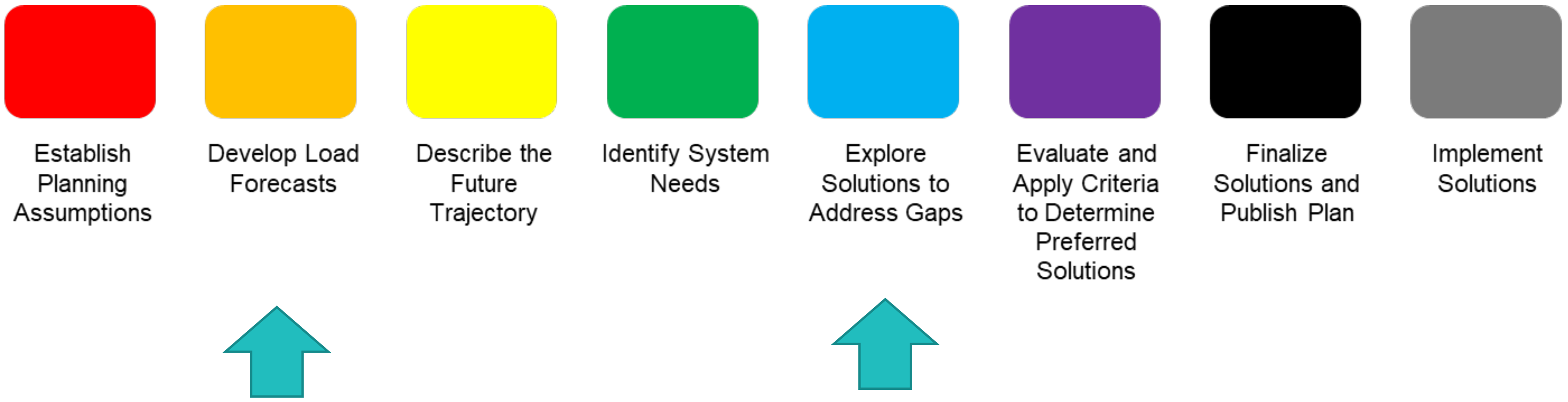
HECO ADMS Proposal (2019)

- Quantified the total costs
- Included only qualitative descriptions of benefits
- Explanation:

  "It is impracticable to aggregate GMS implementation benefits for use in a traditional benefit-cost analysis. Indeed, the GMS investments in general, and the ADMS in particular, are foundational to and enable other programs. GMS investments have interrelated and naturally synergistic functions that make it infeasible to determine the cost-effectiveness of each GMS component independently."

5 Long-range planning

BCA Methods Can Be Integrated into Utility Planning Processes



- Load and DER Deployment Forecasts
- Non-Wires Alternatives

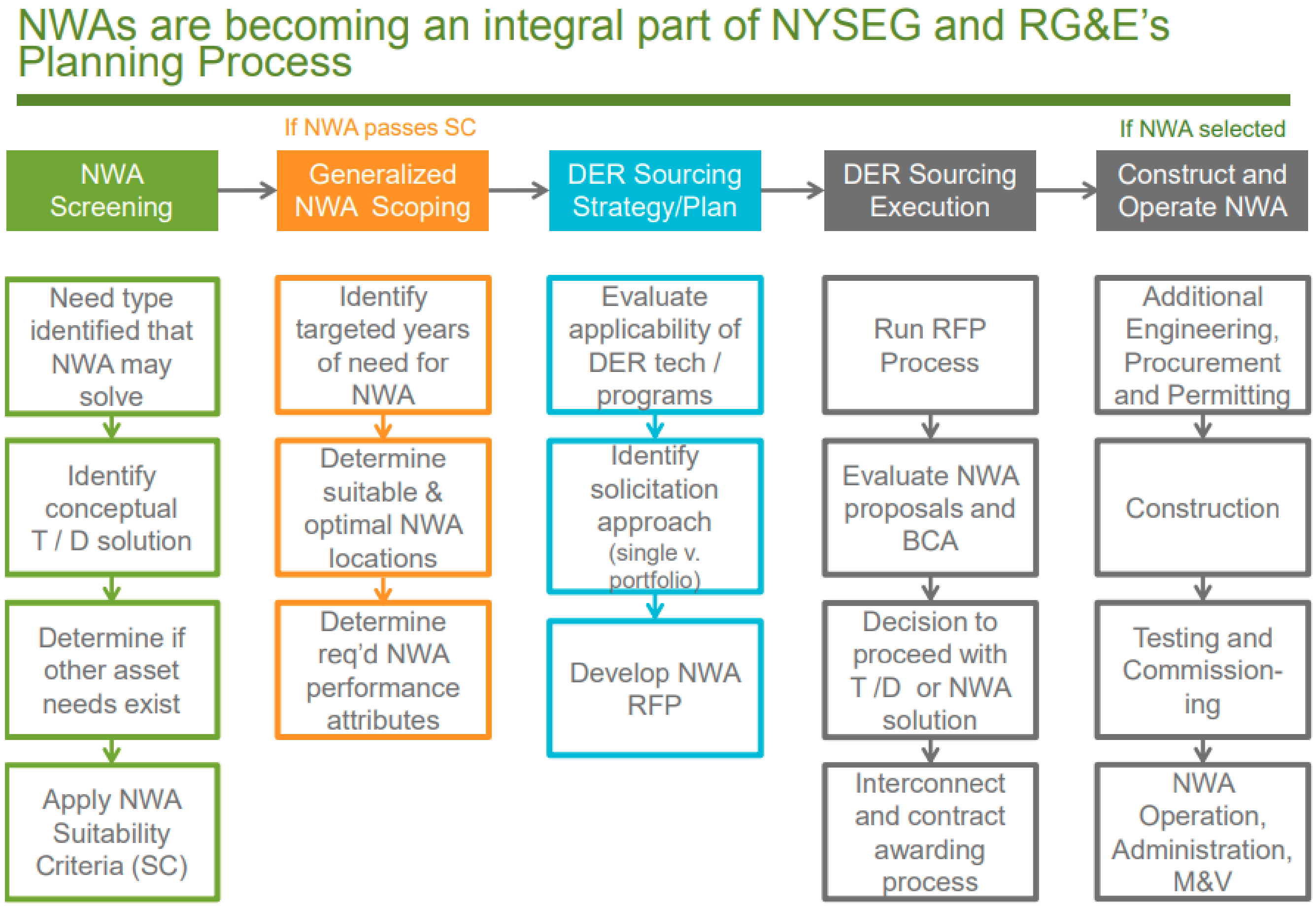
DER Supply Curve Example: Pacificorp (multiple states)

Table 6.13 - Class 2 DSM MWh Potential by Cost Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	27,146	91,695	610,445	972,850	118,725	211,694
10 - 20	8,772	37,868	186,280	869,625	43,968	91,745
20 - 30	10,126	45,728	688,346	588,821	79,553	131,056
30 – 40	14,956	38,417	334,064	411,008	52,584	342,310
40 – 50	9,775	52,426	229,316	483,287	65,569	193,275
50 - 60	4,341	36,941	77,508	530,396	87,588	151,994
60 – 70	17,388	15,456	5,469	455,608	61,885	64,025
70 – 80	9,417	25,123	134,301	220,392	42,658	107,615
80 – 90	5,154	10,915	100,947	108,222	26,837	49,829
90 – 100	10,254	16,337	326,823	73,579	34,445	23,983
100 – 110	11,845	15,402	123,499	73,895	40,142	83,812
110 – 120	5,672	5,813	84,733	81,351	25,457	20,135
120 – 130	2,185	1,895	31,830	135,611	13,624	8,299
130 – 140	1,180	2,936	243	96,048	12,904	7,132
140 – 150	3,650	9,583	8,074	102,483	20,565	19,236
150 - 160	5,327	13,075	5,370	171,330	1,751	12,537
160 – 170	2,948	2,079	11,767	79,327	11,433	31,246

Source: Pacificorp, 2017 IRP, April 2017.

Non-Wires Example: New York



Source: Avangrid, Presentation at Stakeholder Engagement Webinar for DER Sourcing / Non-Wires RFP Process, May 2019.

5 Wrap-up

Key Takeaways

- ✓ BCAs yield different answers than least cost modeling
- ✓ BCAs commonly used to evaluate utility programs offered to customers
- ✓ BCAs occasionally used to evaluate rate designs or utility infrastructure investments, and may not be the best tool in all cases
- ✓ BCA can supplement a LCBF planning process or be integrated into the process

Recommended Reading

- NESP, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*
  - Chapter 12: Non-wires solutions
  - Chapter 13: System-wide DER portfolios
  - Chapter 14: Dynamic system planning
- Woolf, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments*
- ICF, *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*
- US DOE, *Modern Distribution Grid: Strategy and Implementation Planning Guidebook (Volume IV)*

About RAP

The Regulatory Assistance Project (RAP)® is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future.

Learn more about our work at raponline.org

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Using a Consistent BCA Framework to Inform Utility Investment Decisions

Julie Michals

Director of Valuation

E4theFuture

National Standard Practice Manual
for Benefit-Cost Analysis of Distributed Energy Resources
(NSPM for DERs)

Overview

Julie Michals – E4TheFuture

MI Power Grid: Electric Distribution Planning Benefit Cost Analysis Session
November 3, 2021

About NESP

The National Energy Screening Project (NESP) is a stakeholder organization that is open to all organizations and individuals with an interest in working collaboratively to improve cost-effectiveness screening practices for energy efficiency (EE) and other distributed energy resources (DERs).

Products include:

- NSPM for EE (2017)
- NSPM for DERs (2020)
- Database of Screening Practices (DSP)

NESP work is managed by E4TheFuture, with products developed by a consulting team, and state outreach/education via key partners.

NESP work is funded by E4TheFuture and in part by US DOE.

https://nationalenergyscreeningproject.org/

Overview of Presentation

1. NSPM Background

2. NSPM BCA Framework

3. DER Impact Factors (and Cross-Cutting Issues)

3. BCA for Specific DER Technologies

4. BCA for Multiple DERs

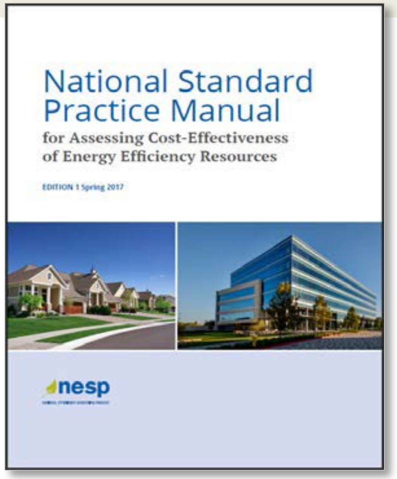
5. Forthcoming New Resources

NSPM for DERs - Background

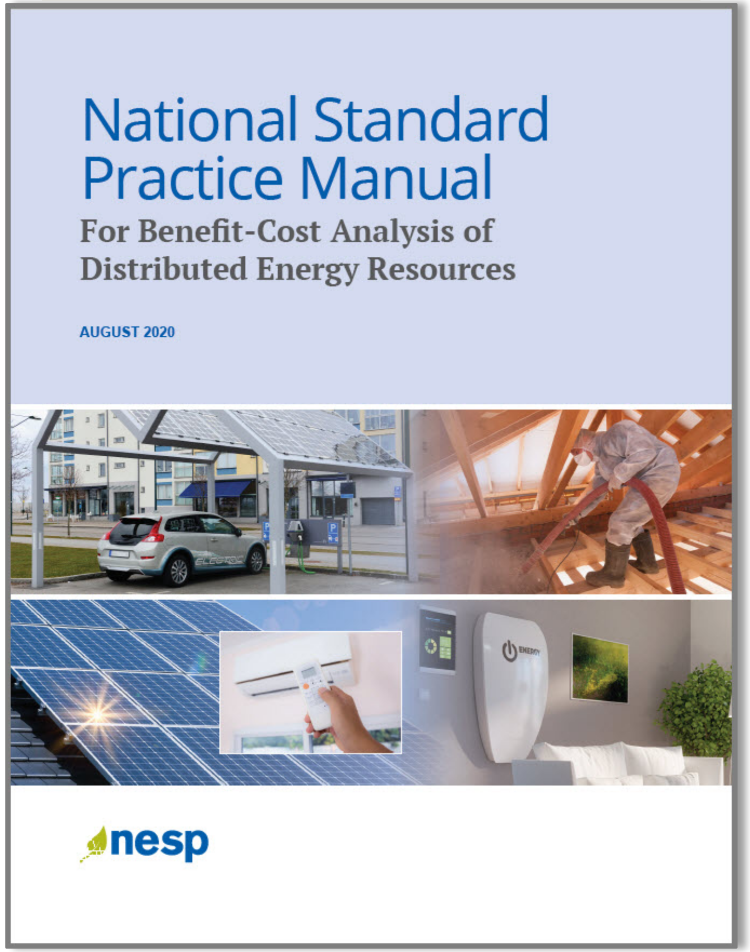
- Managed and funded by E4TheFuture (with support from US DOE via LBNL)
- Multiple co-authors
  - Extensive understanding of regulatory economics
  - Specialized expertise with different DERs
- Advisory Group
  - 45+ individuals
  - Diversity of perspectives
  - Input on Manual outline and drafts
- NSPM for DERs builds on NSPM for EE (2017)

NSPM is a 'living document' and will be updated and improved over time, adding case studies, addressing gaps, etc. contingent upon funding.

NSPM for EE
May 2017



NSPM for DERs
August 2020



The NSPM for DERs incorporates and expands on the NSPM for EE. See comparison

NSPM for DERs – Audience and Uses

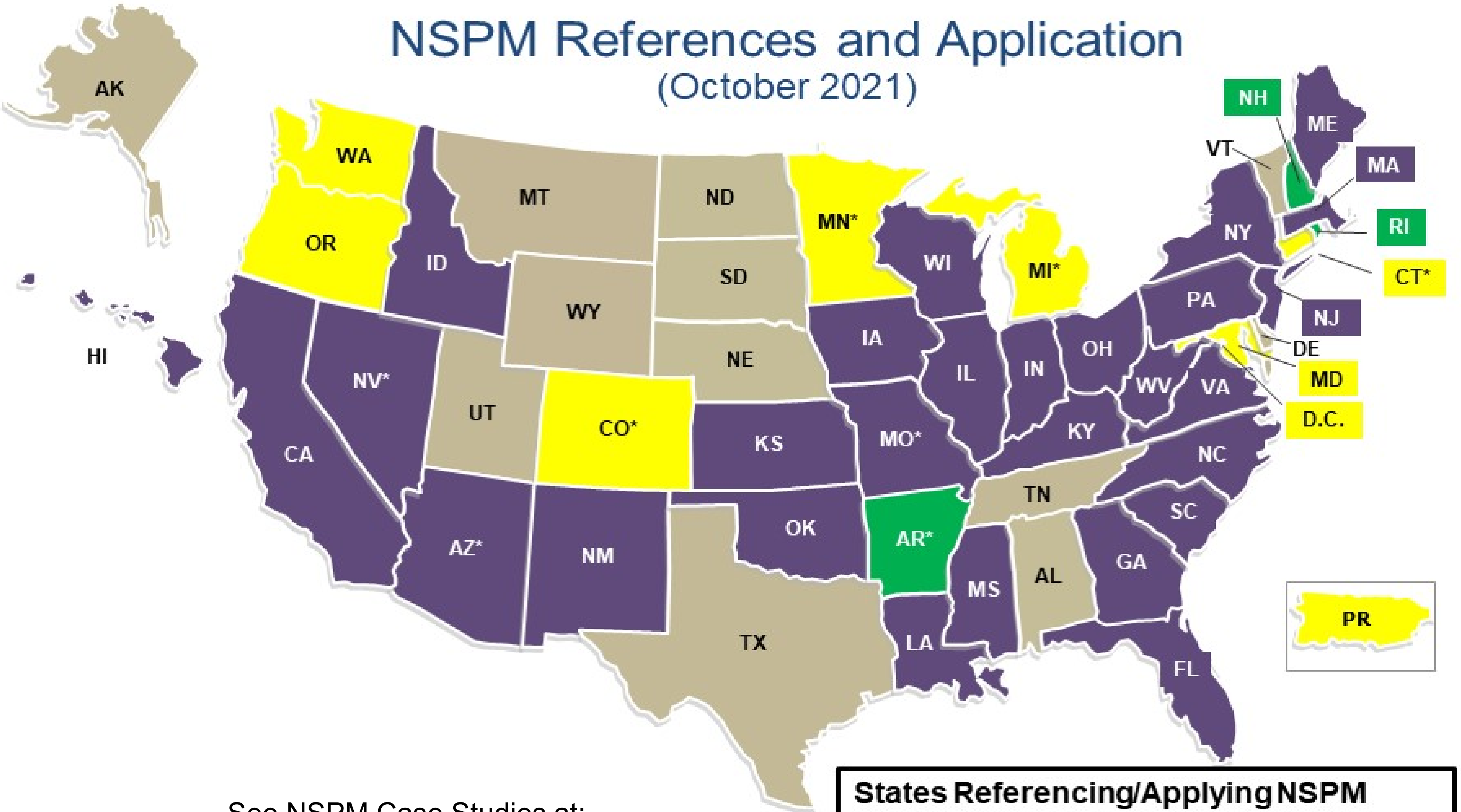
Audience: All entities overseeing/guiding DER decision - PUCs, SEOs, utilities, DER reps, evaluators, consumer advocates, others

Purpose: Guidance for valuing DER opportunities to inform policies and strategies such as:

- Expanding energy efficiency/demand response plans, strategies, and programs to a broader set of DERs;
- Evaluating and planning for non-wires/pipes solutions;
- Incorporating DERs into distribution system planning; and
- Achieving jurisdictional policy goals and objectives, such as:
  - Environmental and carbon emission reductions
  - Strategic electrification, including in buildings and EVs
  - Economic development
  - Energy security

NSPM References and Application

(October 2021)



See NSPM Case Studies at:
https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/case-studies/

States Referencing/Applying NSPM

3	Has applied the NSPM
9	Applying NSPM or under PUC consideration
28	NSPM references made in utility plans, PUC dockets, and/or other jurisdictional documents
*	NSPM references made in most recent quarter

What the NSPM is…

The NSPM provides guidance to help states:

- refine, improve, or develop a primary test using the foundational principles to guide the BCA process
- understand the full range of utility system impacts
- understand the full range of potential non-utility system impacts (depending on their applicable policies)
- understand key factors that affect whether a(n) impact(s) is likely to be a net benefit or cost for a specific DER or combination of DERs

…and what the NSPM is **not.**

The NSPM is not a document that:

- prescribes any specific cost-effectiveness test, nor favor any cost-effectiveness test
- advocates for inclusion of any specific non-utility system impacts (because jurisdictions determine relevant impacts by ensuring alignment with their specific policy goals/objectives)
- adheres or restricts states to theoretical definitions of traditional tests (e.g., the TRC, UCT, or SCT)

NSPM for DERs - Contents

NSPM BCA Framework

Fundamental BCA **Principles**

Multi-Step Process to Develop a **Primary** Cost-effectiveness Test

When and How to Use **Secondary** Cost-Effectiveness Tests

NSPM BCA Principles

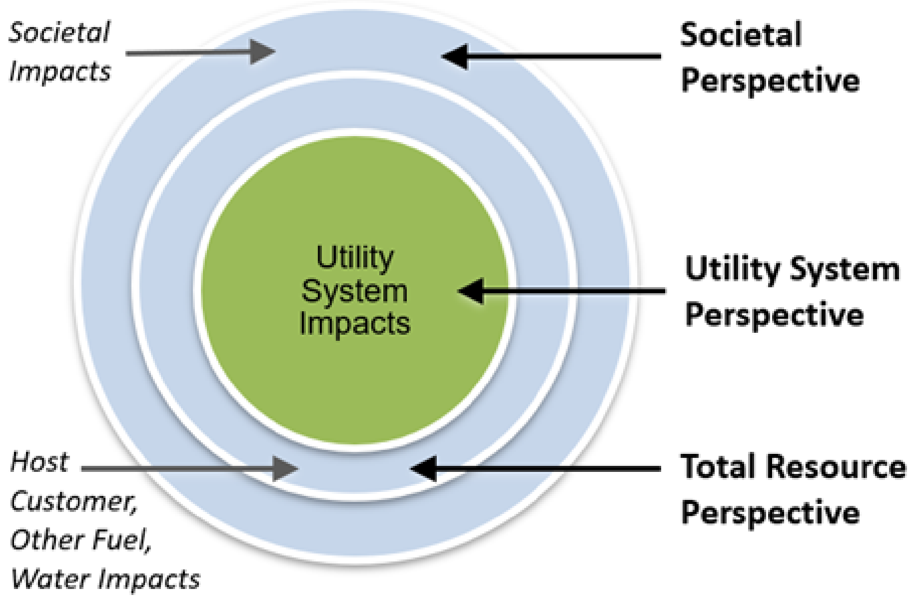
1. Recognize that DERs can provide energy/power system needs and should be compared with other energy resources and treated consistently for BCA.
2. Align primary test with jurisdiction's applicable policy goals.
3. Ensure symmetry across costs and benefits.
4. Account for all relevant, material impacts (based on applicable policies), even if hard to quantify.
5. Conduct a forward-looking, long-term analysis that captures incremental impacts of DER investments.
6. Avoid double-counting through clearly defined impacts.
7. Ensure transparency in presenting the benefit-cost analysis and results.
8. Conduct BCA separate from Rate Impact Analyses because they answer different questions.

Principle #1: Why Consistency in BCA across DERs?

- Consistent BCA framework reduces risk of either over or under-investing in a resource (or combination thereof)
- Siloed approach to valuing different DERs can be complex and overwhelming for commissions, utilities and stakeholders
- Allows for comparison and prioritizing of DER investment options to answer questions such as:
    1. *Which DERs should be implemented, and which should be rejected based on key objectives?*
    2. *Will key policy goals be met by investing in the DER(s)?*
    3. *How can we ensure that customers are not paying too much to achieve policy goals?*

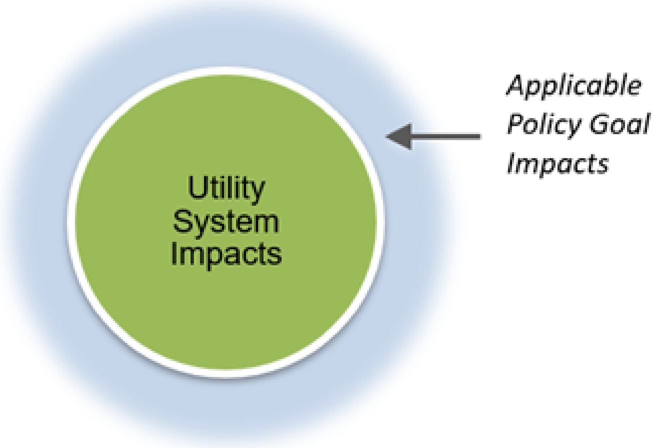
Principle #2 – BCA from whose perspective?

Traditional Perspectives



- Three perspectives define the scope of impacts to include in the most common traditional cost-effectiveness tests.

NSPM for DERs
Regulatory Perspective



- Perspective of public utility commissions, legislators, muni/coop boards, public power authorities, and other relevant decision-makers.
- Accounts for utility system plus impacts relevant to a jurisdiction's applicable policy goals (which may or may not include host customer impacts).
- Can align with one of the traditional test perspectives, but not necessarily.

Developing your Primary Test
(the Jurisdiction Specific Test)

STEP 1	Articulate Applicable Policy Goals
STEP 2	Include All Utility System Impacts
STEP 3	Decide Which Non-Utility System Impacts to Include
STEP 4	Ensure that Benefits and Costs are Properly Addressed
STEP 5	Establish Comprehensive, Transparent Documentation

Principles #3-4: Methodologies/Approaches to Account for Relevant Impacts (Including those that may be hard to quantify)

Approach	Application
Jurisdiction-specific studies	Best approach for estimating and monetizing relevant impacts.
Studies from other jurisdictions	Often reasonable to extrapolate from other jurisdiction studies when local studies not available.
Proxies	If no relevant studies of monetized impacts, proxies can be used.
Alternative thresholds	Benefit-cost thresholds different from 1.0 can be used to account for relevant impacts that are not monetized.
Other considerations	Relevant quantitative and qualitative information can be used to consider impacts that cannot or should not be monetized.

NOTE: Forthcoming NESP Resource (Q1 2022):

Methods, Tools & Resources Handbook *for Quantifying DER Impacts for Benefit-Cost Analysis*

Accounting for “Energy Equity/Justice” in BCAs

Energy Equity Metrics:

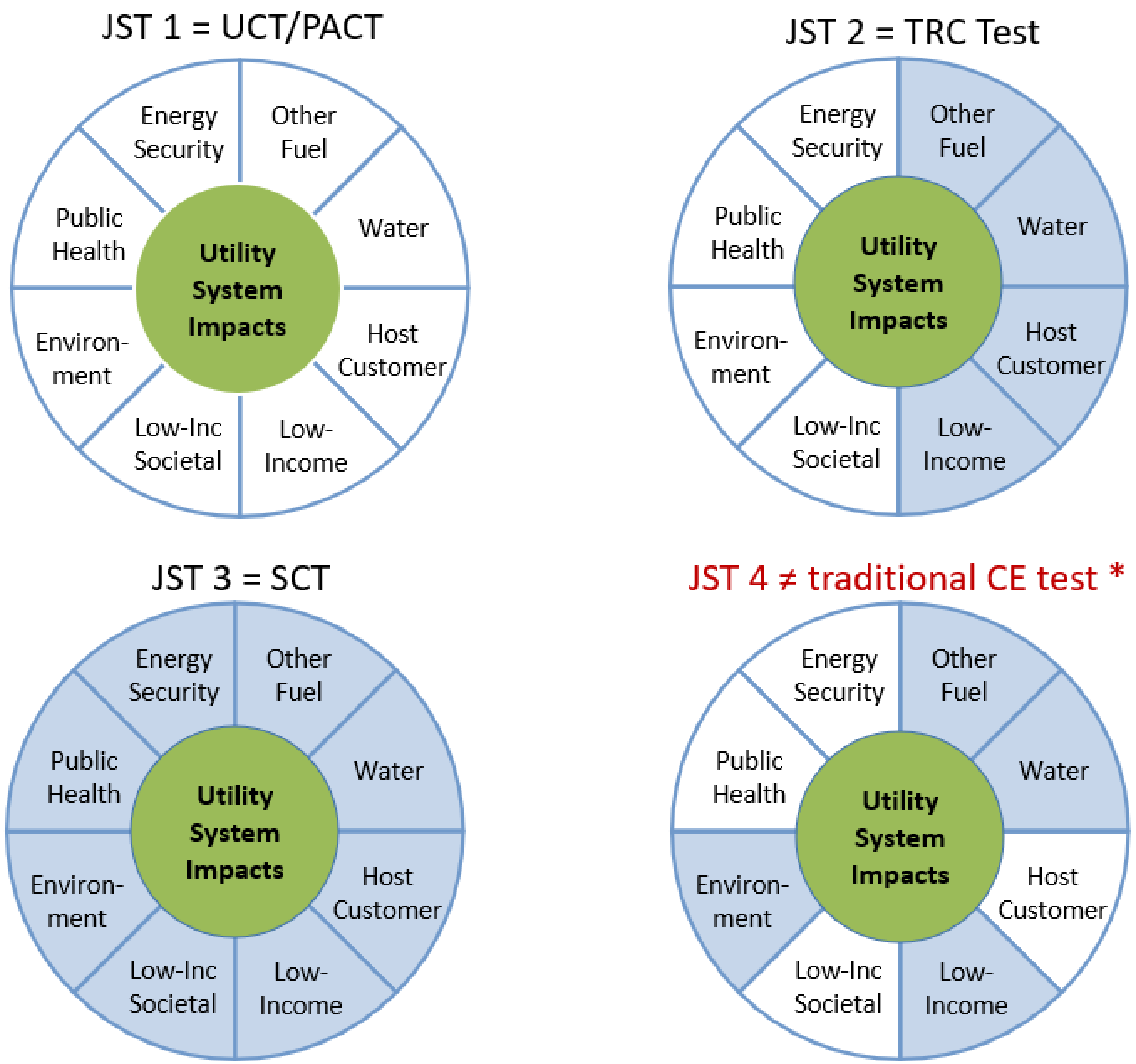
- Overlap with rate and bill analysis;
- Overlap with benefit-cost analysis; and
- Are addressed by many other metrics outside of above analyses

Key Questions/Considerations:

- *How should equity considerations be used to make decisions about utility DER and other resource investments?*
  - Importance of not over-relying on BCA and rate impact analyses, or ‘cherry picking’ metrics (NARUC CPI)
- *How can double counting be avoided?*
- *Need for consistent guidance in industry*
  - Efforts underway by NESP to coordinate with other national developments

Primary Test = Jurisdiction Specific Test (JST)

Hypothetical JSTs as compared to traditional tests



UCT = Utility Cost Test (or PACT = Program Admin Cost Test)
TRC = Total Resource Cost Test
SCT = Societal Cost Test

- All utility system impacts included
- Non-utility system impacts included
- Non-utility system impacts *not* included

*JST 4 includes a different set of non-utility system impacts based on *its applicable policies.*

JSTs may or may not align with traditional tests.

BCA vs Rate Impact Analysis
NSPM Principle #8: keep them separate

The two analyses answer different questions

	Benefit-Cost Analysis	Rate Impact Analysis
Purpose	To identify which DERs utilities should invest in or otherwise support on behalf of their customers	To identify how DERs will affect rates, in order to assess equity concerns
Questions Answered	What are the future costs and benefits of DERs?	Will customer rates increase or decrease, and by how much?
Results Presented	• Cumulative costs (PV$) • Cumulative benefits (PV$) • Cumulative net benefits (PV$) • Benefit-cost ratios	• Rate impacts (c/kWh, %) • Bill impacts ($/month, %) • Participation rates (#, %)

Appendix A of NSPM for DERs

Use of Secondary Tests

NSPM provides guidance on **when and how to use secondary cost-effectiveness tests.**

While a jurisdiction's primary test informs whether to fund or otherwise support DERs, secondary tests can help to:

- inform decisions on how to prioritize DERs (based on priority goals/objectives, as well as different considering perspectives (e.g., host customer/participant, utility);
- inform decisions regarding marginally non- and/or cost-effective DERs; and
- encourage consistency across DER types.

DER Benefits and Costs (Impacts)

Utility System Impacts

- Electric
- Gas
- Other Fuels

Non-Utility System Impacts

- Host Customer
- Societal

Electric Utility System Impacts

Foundational to any BCA test

Type	Utility System Impact
Generation	Energy Generation
	Capacity
	Environmental Compliance
	RPS/CES Compliance
	Market Price Effects
	Ancillary Services
Transmission	Transmission Capacity
	Transmission System Losses
Distribution	Distribution Capacity
	Distribution System Losses
	Distribution O&M
	Distribution Voltage
General	Financial Incentives
	Program Administration
	Utility Performance Incentives
	Credit and Collection
	Risk
	Reliability
	Resilience

Gas Utility System and Other Fuel Impacts

Type	Gas Utility System
Energy/Supply	Fuel and Variable O&M
	Capacity (e.g., local storage)
	Environmental compliance
	Market price effects
Transportation	Pipeline capacity
	Pipeline losses
Delivery	Local delivery capacity
	Local delivery line losses
	Local delivery O&M
General	Financial incentives
	Program admin costs
	Performance incentives
	Credit and collection costs
	Risk, reliability, resilience

Type	Other Fuels*
Other Fuels	Fuel and O&M
	Delivery Costs
	Environmental Compliance
	Market Price Effects

*Other fuels include oil, propane, wood, and gasoline

Host Customer Impacts

(Inclusion depends on policy goals)

Host Customer Impact	Description
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)	Benefits and costs of DERs that are separate from energy-related impacts

Breakout of Host Customer Non-Energy Impacts (NEIs)

Host Customer NEI	Description
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)
Power/ Quality	Refers to the ability of electrical equipment to consume the energy being supplied to it e.g., improved electrical harmonics, power factor, voltage instability and efficiency of equipment.
DER Integration	The ability to add current and future DERs to the existing electric energy grid.
Reduced Utility Bills	Only relevant if using a *Participant Cost Test*

Societal Impacts

(Inclusion depends on policy goals)

Type	Societal Impact	Description
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers
	GHG Emissions	GHG emissions created by fossil-fueled energy resources
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
	Economic and Jobs	Incremental economic development and job impacts
	Public Health	Health impacts, medical costs, and productivity affected by health
	Low Income/Vulnerable Populations: Society	Poverty alleviation, environmental justice, reduced home foreclosures, etc.
	Energy Security	Energy imports and energy independence

Key Factors that Affect DER Impacts

Depends on specific DERs and use cases:

- DER technology characteristics/capabilities, operating profile
- Resource ownership/control
- Temporal and locational impacts
- Interactive effects
- Behind-the-Meter versus Front-of-the-Meter

DER Utility System Impacts

Impact can be a benefit or cost or will ‘depend’ on key factors

Type	Utility System Impact	EE	DR	DG	Storage	Electrification
Generation	Energy Generation	🟢	🟠	🟢	🔴	🔴
	Capacity	🟢	🟢	🟢	🟠	🔴
	Environmental Compliance	🟢	🟠	🟢	🟠	🔴
	RPS/CES Compliance	🟢	🟠	🟢	🔴	🔴
	Market Price Effects	🟢	🟢	🟢	🟠	🔴
	Ancillary Services	🟢	🟢	🟠	🟠	🔴
Transmission	Transmission Capacity	🟢	🟢	🟠	🟠	🟠
	Transmission System Losses	🟢	🟢	🟢	🟠	🔴
Distribution	Distribution Capacity	🟢	🟢	🟠	🟠	🔴
	Distribution System Losses	🟢	🟢	🟢	🟠	🔴
	Distribution O&M	🟢	🟢	🟠	🟠	🔴
	Distribution Voltage	🟢	🟢	🟠	🟠	🔴
General	Financial Incentives	🔴	🔴	🔴	🔴	🔴
	Program Administration Costs	🔴	🔴	🔴	🔴	🔴
	Utility Performance Incentives	🔴	🔴	🔴	🔴	🔴
	Credit and Collection Costs	🟢	🟢	🟢	🟢	🟢
	Risk	🟢	🟢	🟠	🟢	🔴
	Reliability	🟢	🟢	🟠	🟢	🔴
	Resilience	🟢	🟢	🟢	🟢	○

🟢 = typically a benefit
🔴 = typically a cost
🟠 = either a benefit or cost depending on application
○ = not relevant for resource type

DER Host Customer Impacts

Impact can be a benefit or cost or will ‘depend’ on key factors

Type	Host Customer Impact	EE	DR	DG	Storage	Electrification
Host Customer	Host portion of DER costs	🔴	🔴	🔴	🔴	🔴
	Interconnection fees	○	○	🔴	🔴	○
	Risk	🟢	○	🟠	🟢	🟠
	Reliability	🟢	🟠	🟢	🟢	🟠
	Resilience	🟢	🟠	🟢	🟢	🟢
	Tax Incentives	🟢	🟢	🟢	🟢	🟢
	Host Customer NEIs	🟠	🟠	🟠	🟠	🟠
	Low-income NEIs	🟢	🟢	🟢	🟢	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

DER Societal Impacts

Impact can be a benefit or cost or will 'depend' on key factors

Type	Societal Impact	EE	DR	DG	Storage	Electrification
Societal	Resilience	●	●	●	●	●
	GHG Emissions	●	●	●	●	●
	Other Environmental	●	●	●	●	●
	Economic and Jobs	●	●	●	●	●
	Public Health	●	●	●	●	●
	Low Income: Society	●	●	●	●	●
	Energy Security	●	●	●	●	●

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Example: Distributed Storage

Utility System Impacts

🟢 = typically a benefit for this resource type;
🔴 = typically a cost for this resource type;
🟠 = either a benefit or cost for this resource type, depending upon the application or use case of the resource;
○ = not relevant for this resource type.

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
Generation	Energy Generation	🔴	A cost because storage technologies generally require more energy to charge than what they discharge
	Generation Capacity	🟠	A benefit, depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, a cost if storage device charges during peak periods
	Environmental Compliance	🟠	A benefit or cost depending upon system environmental profile during charging and discharging times
	RPS/CES Compliance	🔴	A cost because storage technologies generally require more energy to charge than what they discharge
	Market Price Response	🟠	A benefit or cost depending upon market conditions during charging and discharging times
	Ancillary Services	🟠	A benefit or cost depending upon the storage use case and the electric utility's ability to affect the operation of the storage device
Transmission	Transmission Capacity	🟠	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, potentially costs if storage device charges during transmission peak periods
	Transmission Line Losses	🟠	
Distribution	Distribution Capacity	🟠	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, potentially costs if storage device charges during distribution peak periods
	Distribution Line Losses	🟠	
	Distribution O&M	🟠	
	Distribution Voltage	🟠	
General	Financial Incentives	🔴	Typically costs to the extent they are relevant
	Program Administration Costs	🔴	
	Utility Performance Incentives	🔴	
	Credit and Collection Costs	🟢	A benefit because customer savings make bill payment easier, especially for low-income customers
	Risk	🟢	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage technology during peak or emergency periods
	Reliability	🟢	
	Resilience	🟢	

NSPM for DERs
Multi-DER Guidance

Multiple On-Site DERs
- Costs and Benefits
- BCA Issues and Challenges
- Case Study

Non-Wires Solutions
- NWS Costs and Benefits Summary
- BCA Issues and Challenges
- Case Study

Systemwide DER Portfolios
- Consistent Cost-Effectiveness Tests
- Enabling other DERs and Interactive Effects
- DER Planning Objectives
- Multiple Tests
- Designing and Optimizing DER Portfolios

Dynamic System Planning
- Components of Integrated Distribution Planning
- Early Lessons Learned
- BCA Issues and Challenges

Example: Non-Wires Solutions

BCA Considerations and Challenges

Considerations

- Geo-targeting of DERs in high-value location
- Characteristics of traditional infrastructure project (type, timing, etc.)
- NWS technology characteristics
- Impacts beyond the targeted T&D deferral

Challenges

- Deriving granular locational and temporal values
- Accounting for option value
- Interactive effects between DERs
- Evaluating and measuring NWS impacts
- Accounting for system reliability and risk

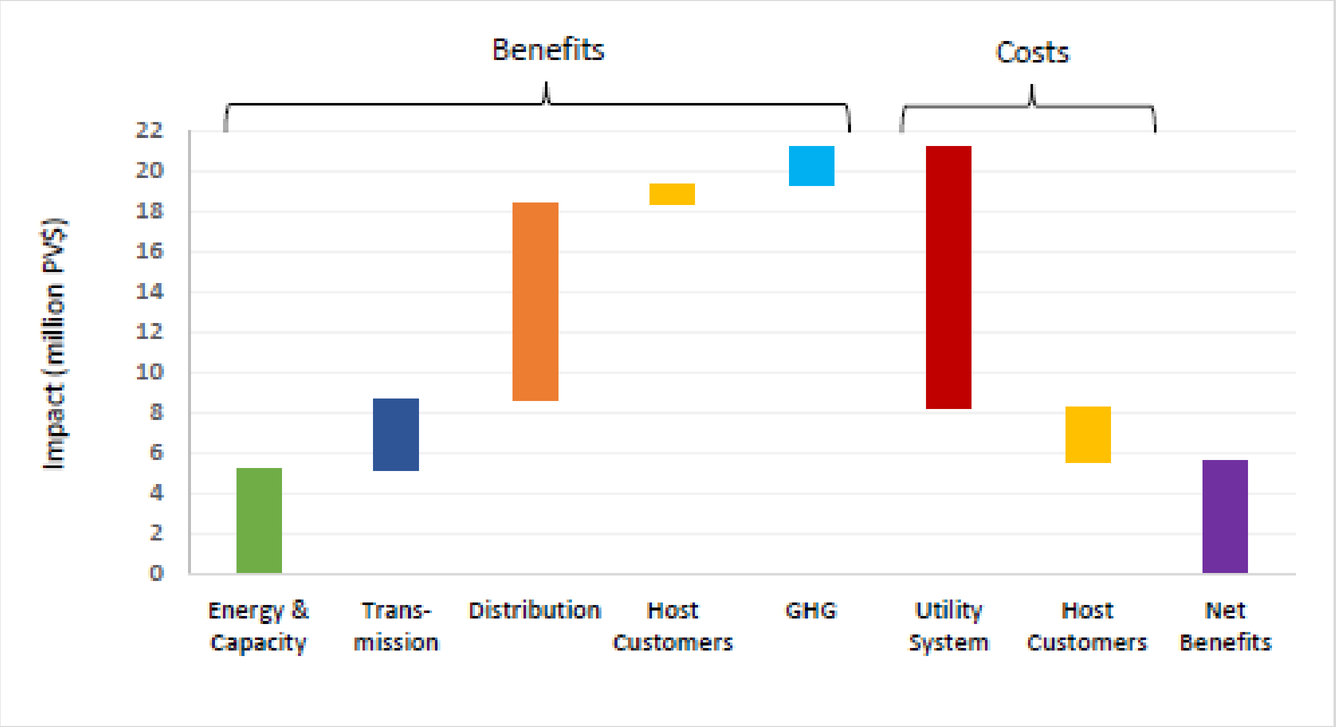
The assessment of NWS cost-effectiveness depends on **where** the program or DERs are located, **when** they provide services, and the resulting benefits and costs.

Non-Wires Solutions

Case Study – NWS Distribution Need

DERs: EE lighting and controls; DR Wi-Fi-enabled thermostats; DPV; and DS (thermal and battery storage)

- Assumes non-coincident with overall system peak (e.g., constrained distribution feeder peaks at 1-5pm, while system peaks at 5-9pm)
- Assumes system-peak hours entail higher marginal emissions rates than NWS = delivers GHG benefits.
- Assumes DER operating profiles where:
    - Storage charges and discharges during system off-peak hours
    - DR reduces and shifts load during system off-peak hours
    - Solar contributes to distribution and some system-peak needs
    - EE has a general downward trajectory on usage



System-Wide DER Portfolios

How should any one utility optimize all DER types?

- What to do in the absence of integrated distribution system planning?

Ideally, each jurisdiction should use a single primary BCA test for all DER types

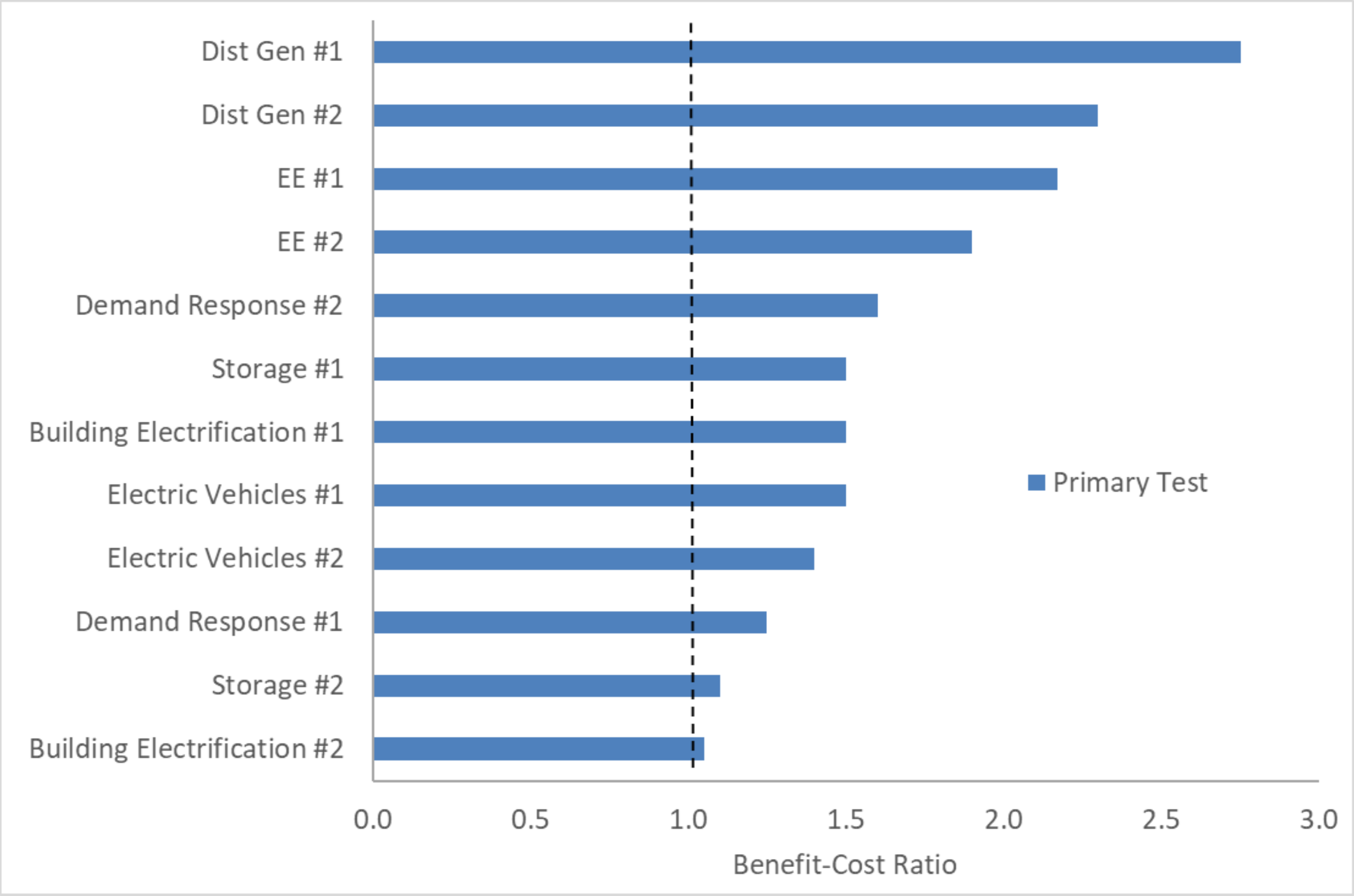
- May require reconciling different policy goals for different DER types

Then, the jurisdiction should identify planning objectives such as:

- Implement the most cost-effective DERs
- Encourage a diverse range of DER technologies
- Encourage customer equity
- Achieve GHG goals at lowest cost
- Avoid unreasonable rate impacts
- Implement all cost-effective DERs
- Achieve multiple planning objectives

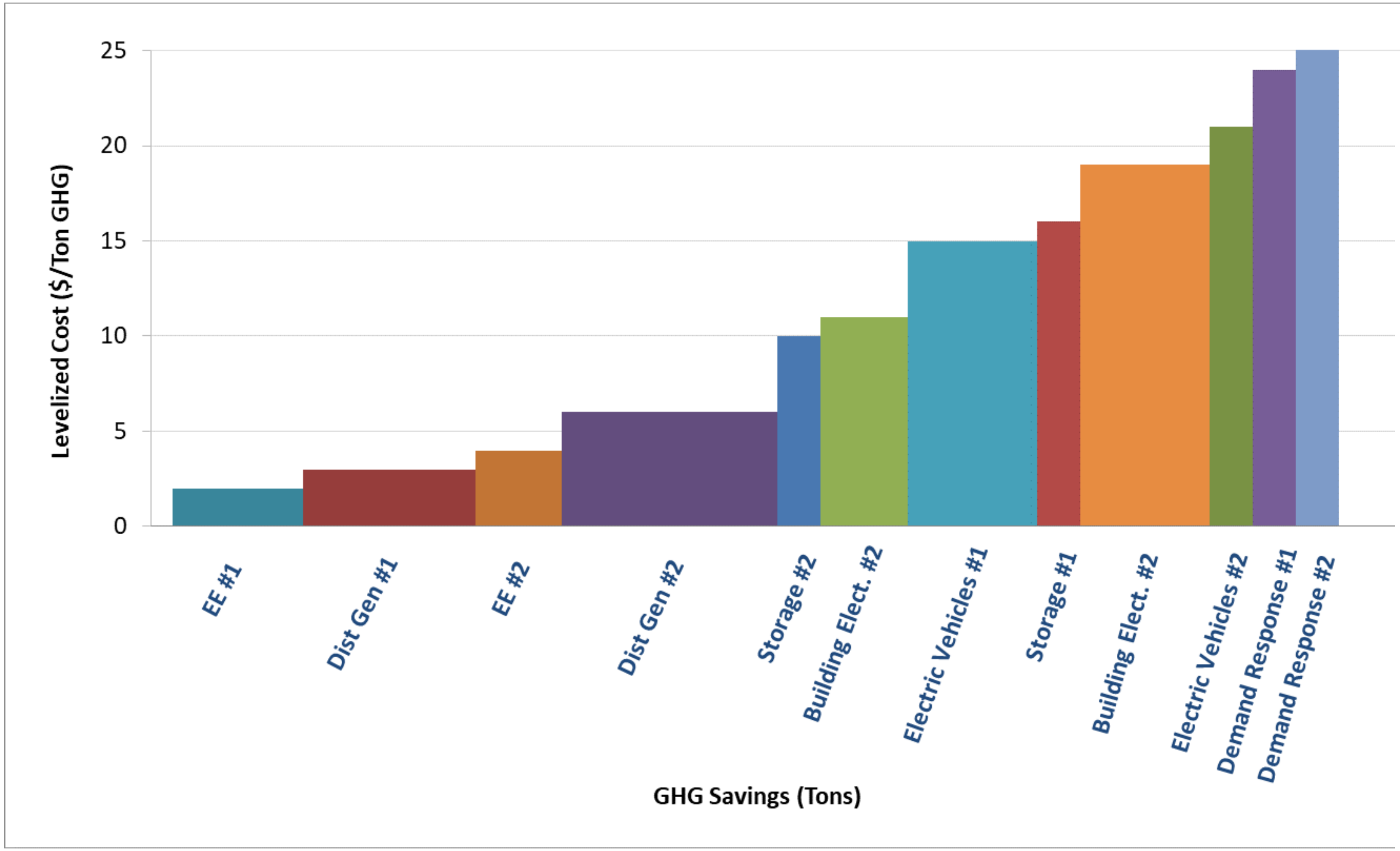
Example of Prioritizing DERs (1)

Objective: to implement the most cost-effective DERs



Sort by benefit-cost ratio and pick those DERs with the highest ratios

Example of Prioritizing DERs (2)
Objective: to achieve GHG goals at lowest cost



Estimate levelized costs.

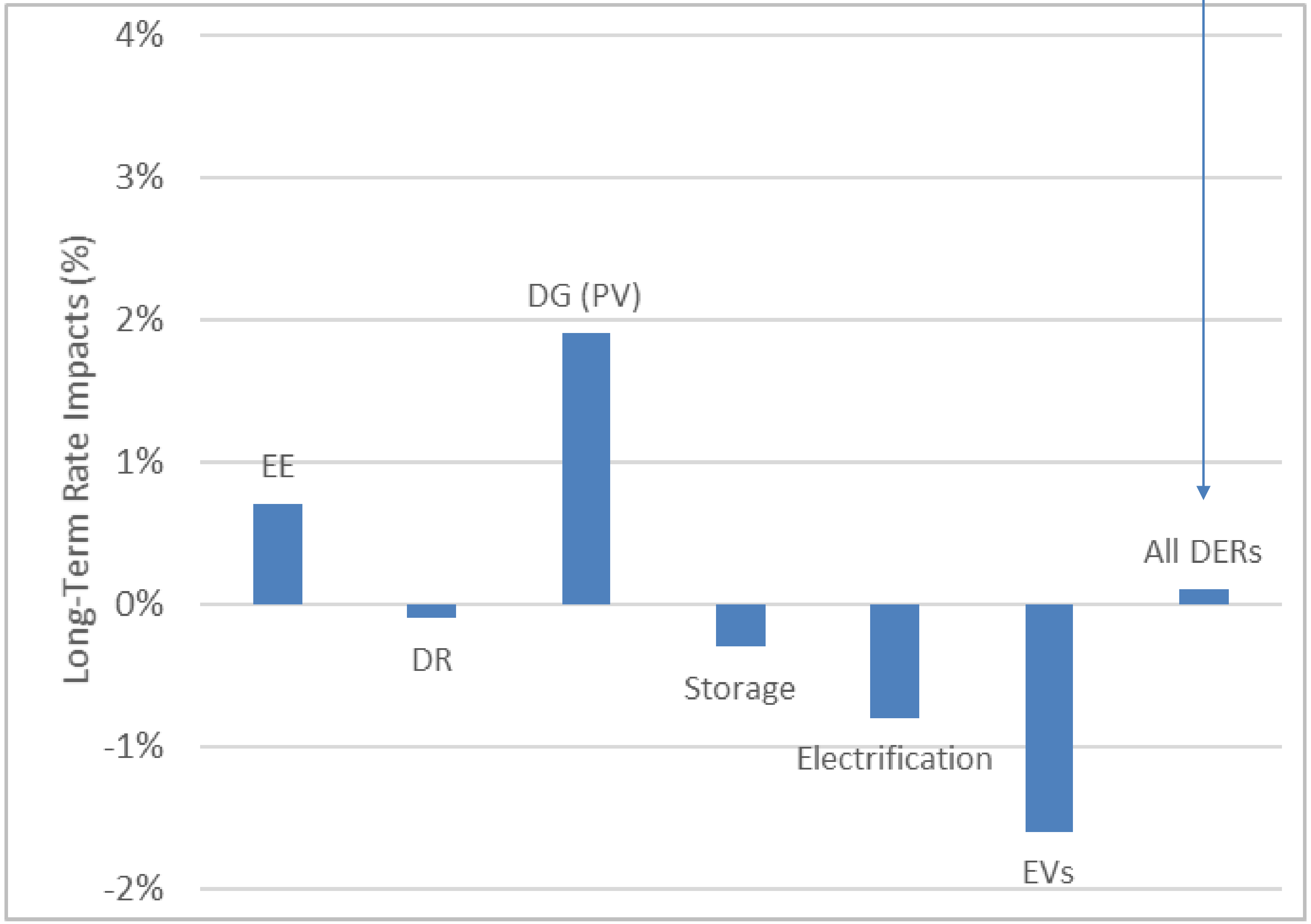
Sort from lowest to highest cost.

Estimate the magnitude of GHG savings by DER.

Use results to determine which DERs will help reach GHG targets.

Example of Prioritizing DERs (3)
Objective: Avoid unreasonable rate impacts

Rate impact analyses should account for combined effect of all DER types



For more information:

NSPM for DERs and supporting resources:

http://www.nationalenergyscreeningproject.org/

Stay informed with the NESP Quarterly **Newsletter**

Questions?

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MI POWER GRID

Making the Most of Michigan's Energy Future

Reconvened Workgroup Meeting:

Distribution Planning Benefit Cost Analysis

Break: 5 minutes

November 3, 2021

1:00PM – 4:00 PM (Eastern)

MPSC

Michigan Public Service Commission

BCA Applications Relevant to Distribution Planning

Tim Woolf

Vice President

Synapse Energy Economics

The Role of Benefit-Cost Analysis in Distribution Planning

MI Power Grid: Electric Distribution Planning Benefit-Cost Analysis Session

November 3, 2021

Tim Woolf
Synapse Energy Economics

Overview

Discuss application of NSPM and key BCA concepts in the context of distribution planning in Michigan

The role of BCA in different regulatory settings

- including distribution system planning

- The choice of BCA test for distribution system planning

BCA versus least-cost, best-fit analyses in distribution planning

- And accounting for non-monetized benefits

Key BCA issues in addressing the Commission’s distribution objectives:

- reliability and resilience
- affordability
- energy equity

The Commission's Overarching Objectives

For the electric distribution system:

1. Safety
2. Reliability and Resilience
3. Affordability and Cost-Effectiveness
4. Accessibility

Source: Michigan Public Service Commission order in Case Nos. U-1799 and U-18014, October 11, 2017, pp. 10-12.

Specific Questions Posed by the Commission

1. Are the measures focused on distribution <u>reliability</u> commensurate with the scale of the challenge?
2. Are the <u>metrics</u> to reduce the number and duration of outages and the number of customers experiencing multiple outages appropriate?
3. Do the financial incentives align the utility's financial goals with the Commission's <u>reliability</u> goals.
4. Do the distribution plans reflect the appropriate balance between needed investments and <u>customer affordability</u>? Are there alternatives that would better strike this balance?
5. Do the distribution plans sufficiently incorporate considerations involving <u>equity</u>, including efforts to avoid further marginalization of vulnerable customers and communities?
6. Are there potential utility pilots or industry best practices that can improve customer safety and reliability by moving overhead lines underground at <u>reasonable cost</u>?

Source: Michigan Public Service Commission order in Case No. U-21122, August 25, 2021, pp. 9-10.

The Role of BCA in Different Regulatory Settings

Context	Application	Goal of BCA	Role of Costs & Benefits
Programs	EE, DR, DG, Storage, EVs	determine whether to implement the program	compare program benefits to costs
Procurement	DERs, NWAs, PPAs,	determine the ceiling price	ceiling price should equal the benefits of the procurement
Pricing	Rate design	estimate long-run marginal costs	long-run marginal costs should equal the benefits of modifying consumption
	DER compensation	determine the value of DER	value of DER is the sum of benefits
Planning	Optimize DERs	identify optimal DER portfolio	compare portfolio benefits to costs
	DP, IDP, IRP, IGP	identify preferred resource scenario	compare scenario benefits to costs
	GHG plans	achieve GHG goals at low cost	compare GHG plan benefits to costs
	State Energy Plans	identify resources to meet state goals	compare state plan benefits to costs
Infrastructure Investments	Grid Mod, AMI, EV infrastructure, etc.	determine whether to make the investment	compare investment benefits to investment costs
Prudence Reviews	Retrospective review	determine whether past utility decision was appropriate	compare benefits and costs using test in place at the time the decision was made
	Prospective review	determine whether proposed utility decision is appropriate	compare benefits and costs using test currently in place

The Role of BCA in Rate Cases

Many of the assessments listed above take place within rate cases.

For example:

- Costs for DER programs are sometimes reviewed and recovered in rate cases.
- Costs of resource procurement are sometimes reviewed in rate cases.
- Rate design and TOU rates are often designed within a rate case.
- Planning activities typically occur outside of rate cases. However, the cost recovery allowed in a rate case should ideally be informed by and consistent with the results of planning activities.
- Infrastructure investments are
  - Sometimes reviewed by regulators prospectively outside of a rate case.
  - Sometimes reviewed by regulators retrospectively within a rate case.
- Prudence reviews often take place within a rate case.

The Planning Continuum

- Bulk Power System Planning
  - integrated resource planning
  - ISO/RTO planning
  - transmission planning
- Distribution Planning
  - distribution reliability
  - grid modernization
  - non-wires alternatives
  - BCA and LCBF
- DER Assessment and Planning
  - BCA of DERs

Consistent BCA principles and concepts should be applied across all of these.

See NASEO/NARUC Task Force on Comprehensive Electricity Planning
for current efforts to better integrate all these: https://www.naruc.org/taskforce/

Choice of BCA Test for Distribution Planning

- The same principles and concepts used to develop BCA tests for DERs should be used to develop BCA tests for distribution planning
- The same primary test (i.e., Jurisdiction Specific Test) used for DERs should be used for distribution planning
- Otherwise, you can end up with uneconomic outcomes
- For example:
  - If a Total Resource Cost test is used for DERs
  - And a Societal Cost test for is used for distribution planning
  - Then the DER planning results will not reveal some of the DERs that might be useful in reducing societal impacts in the distribution planning process

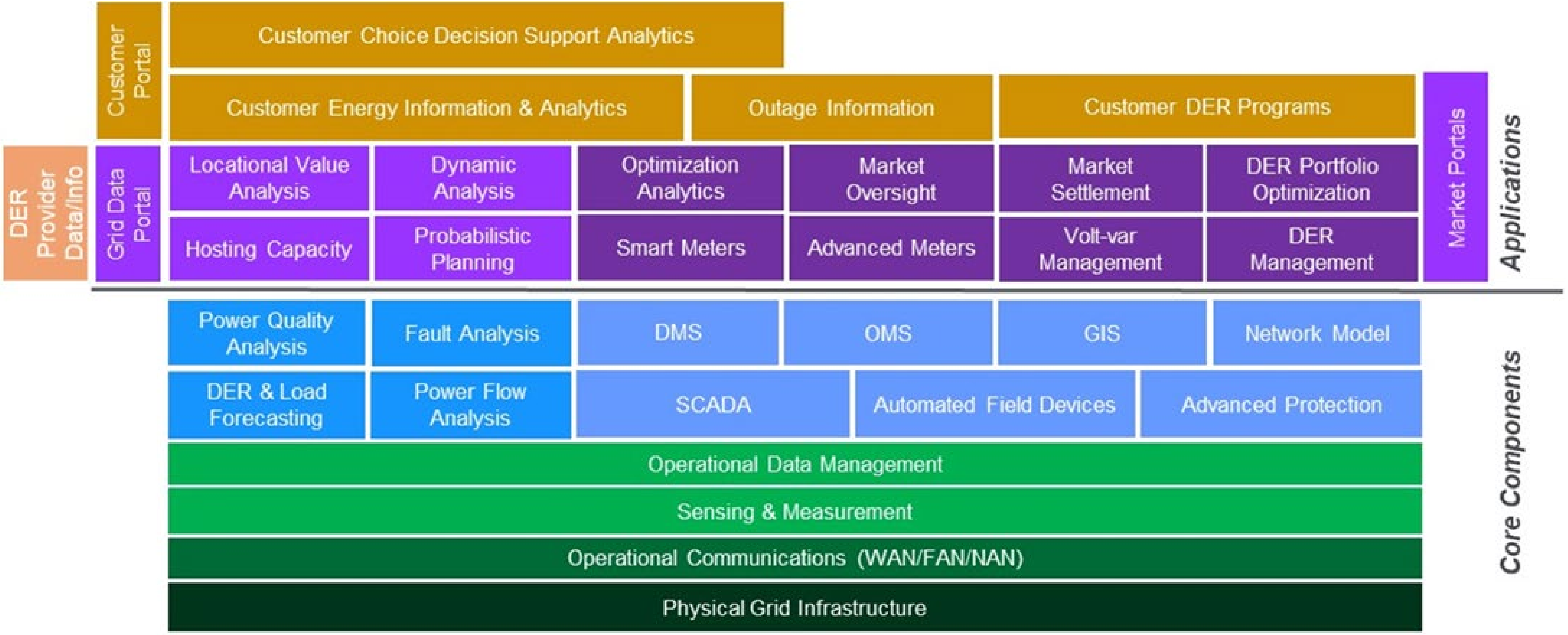
BCA Tests for DERs and Distribution Planning

Impact	Perspective	DER BCA (from the NSPM for DERs)	Distribution Planning BCA (from Consumers 2021 Distribution Plan)
Costs	Utility System	• customer incentives • program administration • utility incentives • equipment costs	• capital costs • O&M costs • ancillary service costs • equipment costs
	Affected Customers	• measure costs • non-energy costs • other fuel costs	• none
	Society	• environmental • economic development • other	• environmental • economic development • other
Benefits	Utility System	• energy • capacity • ancillary services • T&D, T&D losses • credit & collection • reliability & resilience	• energy • capacity • ancillary services • T&D losses • O&M • avoided costs of restoring outages
	Affected Customers	• non-energy benefits • other fuel savings • reliability &resilience	• avoided customer outage costs
	Society	• environmental • economic development • reliability & resilience • other	• environmental • economic development • avoided societal outage costs • other

BCA vs. Least-Cost Best-Fit

- The main difference is that LCBF does not require estimates of benefits – it is presumed that the investment is needed
  - For years, this approach has been sufficient distribution planning because it was applied to investments that were needed to maintain reliability.
- A BCA provides much more information than LCBF
  - BCA provides certainty as to whether benefits exceed costs.
- LCBF should be used only when necessary
- Deciding when to use LCBF
  - Are there a lot of benefits that are not monetizable? Maybe use LCBF.
  - Is the investment needed for reliability or resilience? Maybe use LCBF.
  - Is the investment needed to meet regulatory policy goals? BCA is preferable.
  - Is the investment considered a core or platform? Maybe use LCBF.
- Non-monetized benefits should be accounted for as much as possible
  - Regardless of whether BCA or LCBF is used

Core Components Versus Applications



Source: US DOE 2017, *Modern Distribution Grid: Decision Guide,* Volume III, page 26, Figure 8.

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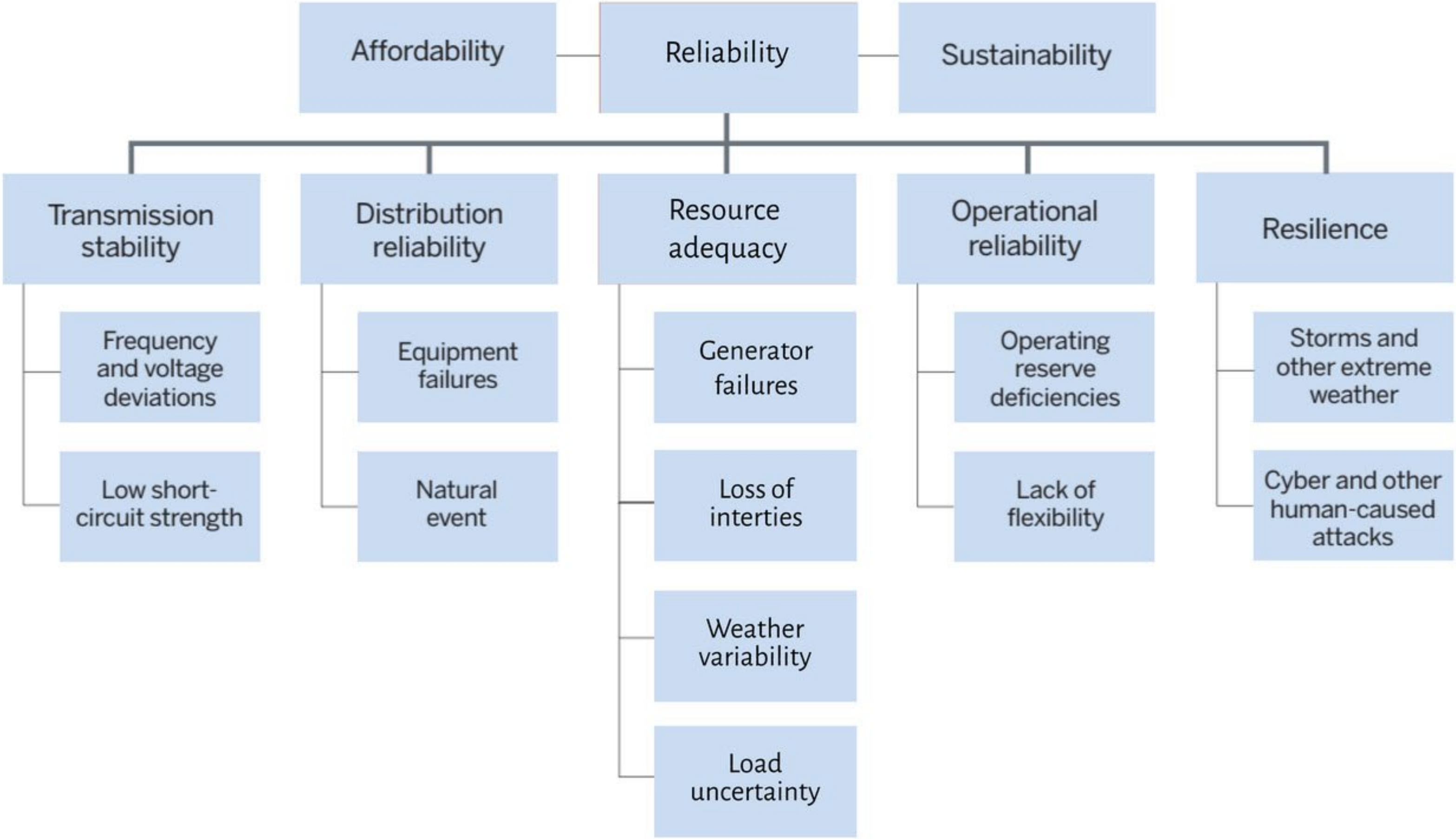
Accounting for Non-Monetized Benefits

- Put as many benefits as possible in monetary terms
- Define benefits in such a way that they can be monetized
- Provide as much quantitative data as possible
- Apply the least-cost, best-fit framework - where warranted
  - This approach does not require monetization of benefits.
- Establish metrics to assess benefits
  - Metrics do not need to be in monetary terms
- Use quantitative methods to address non-monetized benefits:
  - use a point system to assign value to non-monetized benefits
  - assign proxy values for significant non-monetized benefits
  - use a weighting system to assign priorities to non-monetized benefits
  - use multi-attribute decision-making techniques

Source: Synapse Energy Economics, Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments, Grid Modernization Laboratory Consortium, February 2021.

Reliability and Resilience



Source: JP Carvallo, *Quantifying Reliability and Resilience Impacts of Energy Efficiency: Examples and Opportunities*, presented at the ACEEE Energy Efficiency as a Resource Conference, October 26, 2021.

Reliability and Resilience

Reliability

- The ability of the system or its components to prevent or withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components (US DOE)
- The ability of the system to deliver power in the face of routine uncertainty in operation conditions (LBNL)
- Metrics and methods are standardized and widely accepted

Resilience

- Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event (NARUC 2013).
- The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them (US DOE 2013).
- The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the ability to anticipate, absorb, adapt to, and/or rapidly recover from such an event (FERC 2018).
- The ability of the system and its components (i.e., both the equipment and human components) to minimize the damage and improve recovery from the non-routine disruptions, including high impact, low frequency events, in a reasonable amount of time" (NATF 2021).

Key distinction is that reliability pertains to routine events while resilience pertains to extraordinary events

Key Steps for Assessing Reliability

1. Define reliability metrics.
2. Define and quantify baseline reliability.
   - The reliability for a Reference Case.
3. Characterize the potential reliability impacts of DERs.
   - These are different for different types of DERs, e.g., EE versus DR, versus PV, versus storage
4. Quantify the reliability impacts from the relevant DERs.
   - The reliability for a DER Case.
5. Calculate the net reliability impacts of the relevant DERs.
   - Difference between the Reference Case and the DER Case.
6. Methods for determining monetary value of improved reliability
   - Stated preferences
   - Revealed preferences
   - Quantitative models (e.g., the LBNL ICE model)

Reliability Metrics

Distribution System	System Average Interruption Duration Index (SAIDI)
	System Average Interruption Frequency Index (SAIFI)
	Customer Average Interruption Duration Index (CAIDI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Customers Experiencing Multiple Interruptions (CEMI)
	Customers Experiencing Longest Interruption Duration (CELID)
Transmission System	N-1 analysis
	Loss-of-Load Probability (LOLP)
	Loss-of-Load Expectation (LOLE)
System-Wide Metrics	Planning Reserve Margin
	Effective Load Carrying Capacity (ELCC)
	LOLP and LOLE
Monetary	Value of Lost Load (VOLL)
	Customer Interruption Costs (CIC)
	Service Restoration Costs

Key Steps for Assessing Resilience

1. Characterize the threats.
2. Define reliability metrics.
3. Define and quantify baseline resilience.
4. Characterize the potential resilience impacts of DERs.
5. Quantify the resilience impacts from the relevant DERs.
6. Calculate the net resilience impacts of the relevant DERs.
7. Methods for determining monetary value of improved resilience.
   - Some of the same methods used for reliability can be used for resilience
   - Additional methods are needed
     - For example, how to customer interruption costs differ for routine outages relative to extraordinary outages?

These four steps are essentially the same steps used for reliability

Resilience Metrics

Impact	Consequence Category	Resilience Metrics
DIRECT	Electric Service	Cumulative customer-hours of outages
		Cumulative customer energy demand not served
		Average number (or %) of customers experiencing an outage during a specified time
	Critical Electrical Service	Cumulative critical customer-hours of outages
		Critical customer energy demand not served
		Average number (or %) of critical loads that experience an outage
	Restoration	Time to recovery
		Cost of recovery
	Monetary	Loss of utility revenue
		Cost of grid damages (e.g., repair or replace lines, transformers)
		Cost of recovery
		Avoided outage cost
INDIRECT	Community Function	Critical services without power (e.g., hospitals, fire stations, police stations)
	Monetary	Loss of assets and perishables
		Business interruption costs
		Impact on the gross municipal product (GMP) or gross regional product (GRP)
	Other Critical Assets	Key production facilities without power
		Key military facilities without power

Source: Institute of Electrical and Electronic Engineers (IEEE) 2021. Resilience Framework, Methods, and Metrics for the Electricity Sector, Bill Chiu. IEEE Technical Report PES-TR65. February 10, page 14

Reliability & Resilience

- Which perspectives do reliability and resilience affect?
  - Utility system perspective
  - Host customer perspective
  - All customer perspective
  - Societal perspective
  - All the above
- Does it matter?
- Maybe not
  - If a jurisdiction has a policy to improve reliability and resilience, then those impacts should be included in the JST.
  - For the purpose of describing and estimating reliability and resilience impacts, it is useful to categorize them.
  - For secondary tests, e.g., Utility Cost Test, it would be useful to categorize them.

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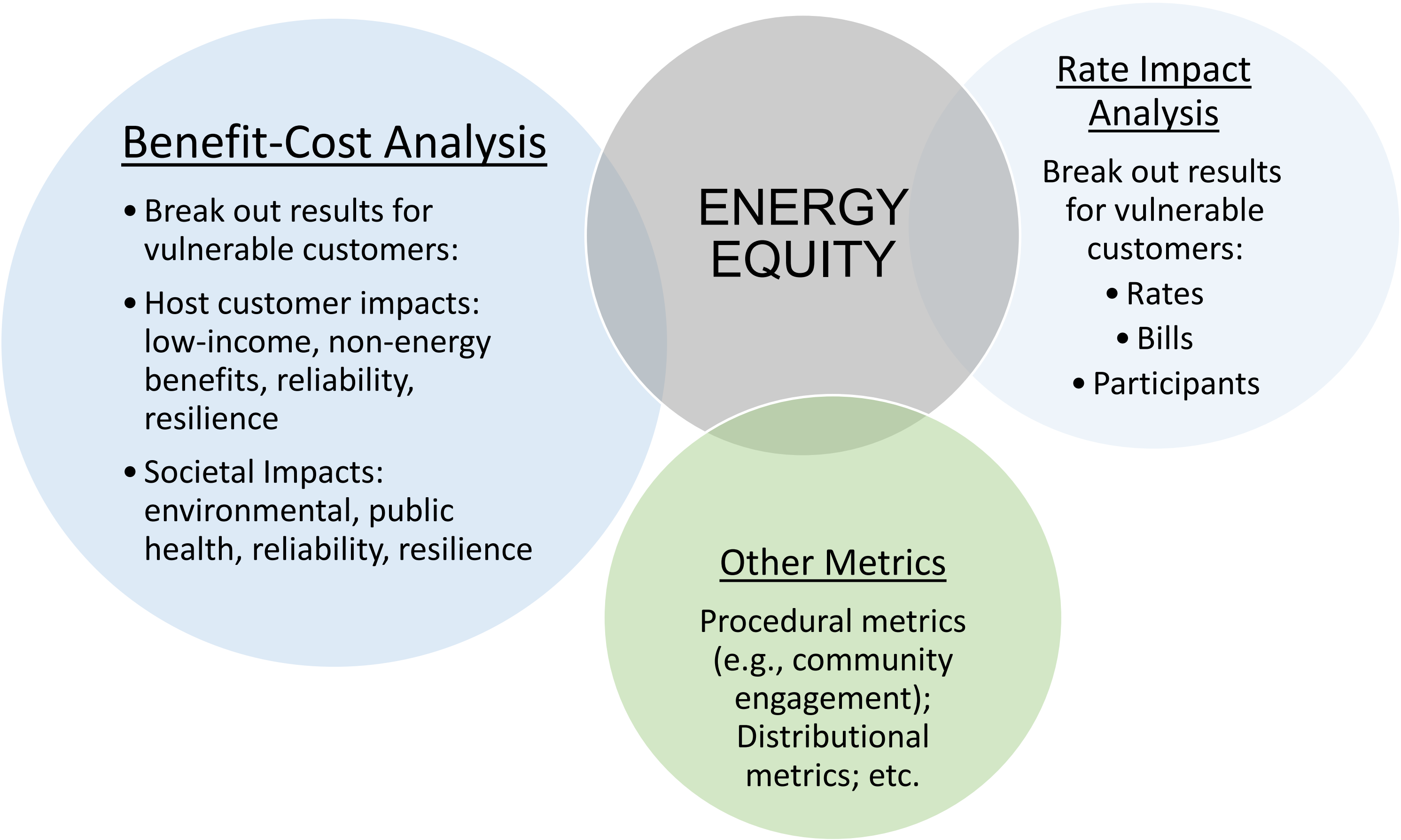
Affordability

- Costs on the utility system
  - The Utility Cost test is the best way to indicate lowest utility system costs
  - The Utility Cost test could be used as a secondary test to assess affordability
  - Note that this test does not account for other policy goals
- Cost impacts on customers
  - Bill impact analyses very useful for assessing affordability
  - Bill impact analyses will provide the same results as the Utility Cost Test but with different metrics
    - UCT: system-wide costs, benefits, net benefits, benefit-cost ratios
    - Bill impacts: dollars/month, by customer type
- Equity
  - Affordability is different for different customers
  - Especially low-income and vulnerable customers

Equity in the Context of BCA



Equity in the Context of Distribution Planning

Questions to assess equity issues:

1. Is this the lowest cost plan for the desired outcomes?
    - BCA and LCBF help answer this question.
2. What are the long-term bill impacts of the plan?
    - Including impacts on vulnerable customers.
3. Does the plan provide equitable reliability and resilience benefits?
    - Especially for vulnerable customers and communities.
    - Have these customers received equitable services in the past?
    - Does the proposed plan improve or worsen reliability or resilience for them?
4. Does the plan provide equitable access to DERs & grid services
    - Especially for vulnerable customers and communities

Questions and Answers

Contact Information

Synapse Energy Economics
is a research and consulting firm specializing in technical analyses of energy, economic, and environmental topics. Since 1996 Synapse been a leader in providing rigorous analysis of the electric power and natural gas sectors for public interest and governmental clients.

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BCA Issues Specific to Michigan

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National Association of Regulatory Utility Commissioners

Julie Michals
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E4theFuture

John Shenot
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Interruption Cost Estimate (ICE) Calculator

Joe Eto

Senior Advisor

Lawrence Berkeley National Laboratory

Interruption Cost Estimate (ICE) Calculator

Joe Eto

Lawrence Berkeley National Laboratory

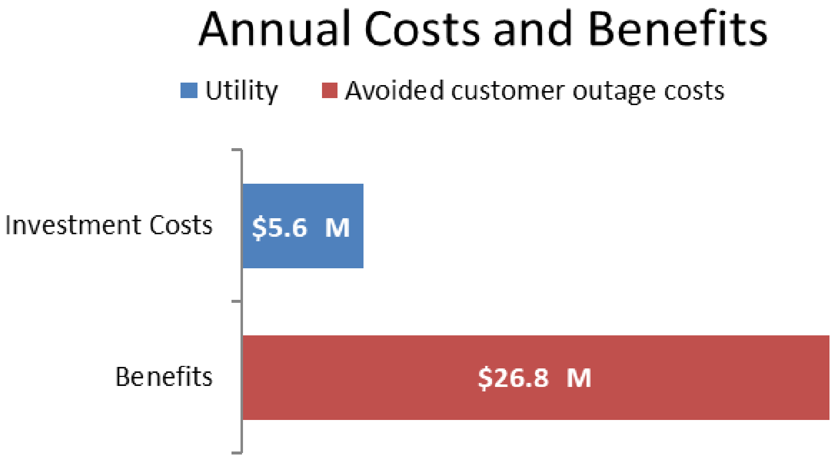
MI Power Grid

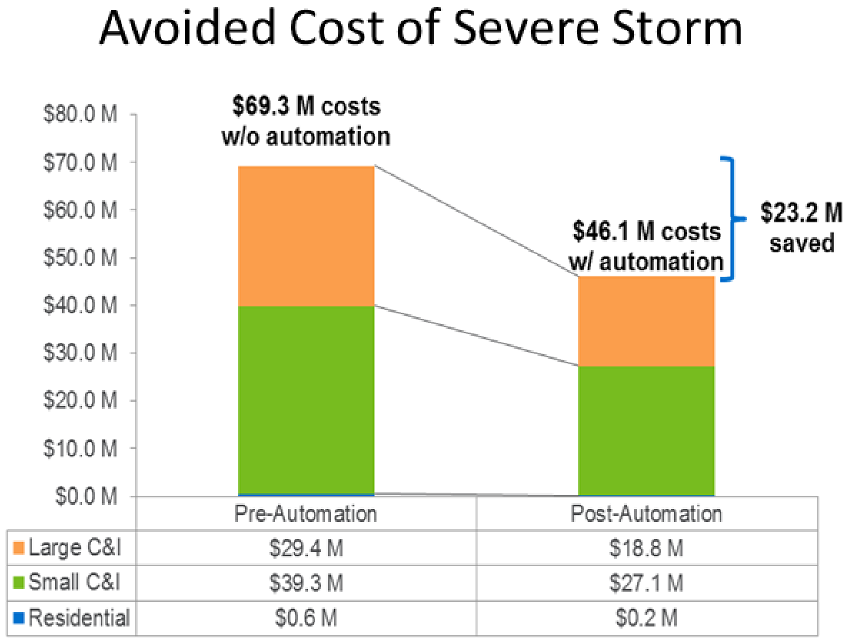
Electric Distribution Planning Benefit Cost Analysis Session

November 3, 2021

Reliability Value-Based Planning example: Estimating Customer Benefits of Distribution Automation

- Utility: EPB of Chattanooga
- Customers Impacted: 174,000 customers (entire territory)
- Investment: 1,200 automated circuit switches and sensors on 171 circuits
- Reliability Improvement:
  - SAIDI ↓45% (from 112 to 61.8 minutes/year)
  - SAIFI ↓51% (from 1.42 to 0.69 interruptions/year) (between 2010 and 2015)





The Costs to Customers of Power Interruptions

Varies by type of customer and depends on when and for how long their lights are out

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Morning	$8,133	$11,035	$14,488	$43,954	$70,190
Afternoon	$11,756	$15,709	$20,360	$59,188	$93,890
Evening	$9,276	$12,844	$17,162	$55,278	$89,145
Small C&I					
Morning	$346	$492	$673	$2,389	$4,348
Afternoon	$439	$610	$818	$2,696	$4,768
Evening	$199	$299	$431	$1,881	$3,734
Residential					
Morning	$3.7	$4.4	$5.2	$9.9	$13.6
Afternoon	$2.7	$3.3	$3.9	$7.8	$10.7
Evening	$2.4	$3.0	$3.7	$8.4	$11.9

The Interruption Cost Estimate (ICE) Calculator

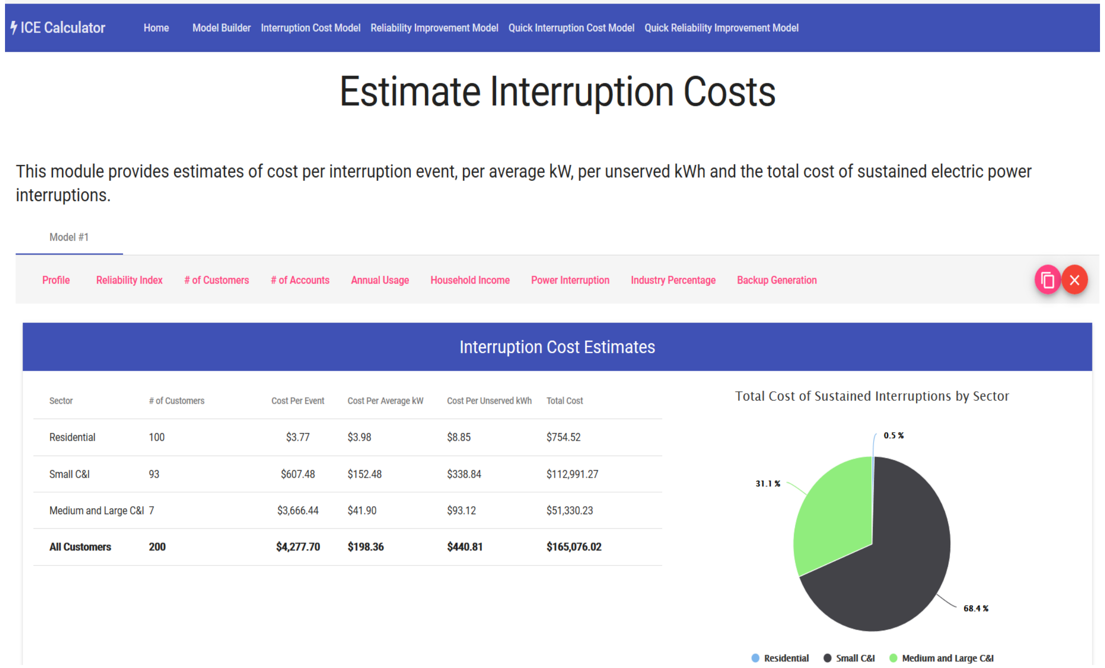
Customer costs of power interruptions are of increasing importance for identifying and prioritizing cost-effective utility investments to improve reliability/resilience

Berkeley Lab's Interruption Cost Estimate (ICE) Calculator is the leading and only publicly-available tool for estimating the customer cost impacts of power interruptions

The ICE Calculator is being used to:

- Support internal utility reliability planning activities
- Provide a basis for discussing utility reliability investments with regulators
- Assess the economic impact of past power outages

ICE CALCULATOR



http://www.icecalculator.com/

ICE Calculator Based on 100,000+ Utility-sponsored Surveys of the Costs Customers Incur When the Lights Go Out

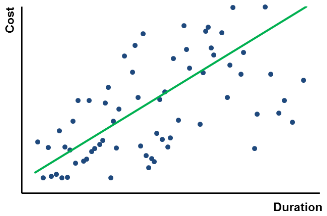
Forecast of Reliability

- SAIFI (frequency)
- SAIDI (mins. interrupted)
- w/ and w/o investment

Customer Survey Meta-database

- 34 surveys
- 10 utilities
- 1989-2012
- N=105,000

Econometric Meta-analysis



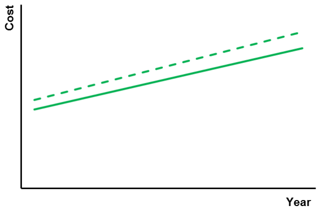
- Med/large C&I
- Small C&I
- Residential
- Other factors

ICE CALCULATOR

Customer Characteristics

- Customer class
- Usage (kWh)
- Industry

Forecast of Customer Outage Costs



- ICE Calculator output
- w/ and w/o investment

Updated analysis with new surveys and model coefficients published in 2015
https://emp.lbl.gov/publications/updated-value-service-reliability

Motivation for National Initiative to Upgrade the ICE Calculator

- Currently, the utility survey-based information relied on by the ICE Calculator is:
  - Dated—many of the surveys are 25+ years old
  - Not statistically-representative for all regions of the U.S.
  - Not appropriate for estimating costs of widespread, long-duration (> 24 hour) interruptions

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
Southeast-1	1997	90			0	1
Southeast-2	1993	3,926	1,559	3,107	0	4
	1997	3,055	2,787	3,608	0	12
Southeast-3	1990	2,095	765		0.5	4
	2011	7,941	2,480	3,969	1	8
Midwest-1	2002	3,171			0	8
Midwest-2	1996	1,956	206		0	4
West-1	2000	2,379	3,236	3,137	1	8
West-2	1989	2,025	5		0	4
	1993	1,790	825	2,005	0	4
	2005	3,052	3,223	4,257	0	8
	2012	5,342	4,632	4,106	0	24
Southwest	2000	3,991	2,247	3,598	0	4
Northwest-1	1989	2,210		2,126	0.25	8
Northwest-2	1999	7,091		4,299	0	12

- With encouragement and support from DOE and the Edison Electric Institute (EEI), Berkeley Lab is upgrading the ICE Calculator through direct funding by sponsoring U.S. utilities.

Plan to Update and Upgrade the ICE Calculator

Berkeley Lab, Edison Electric Institute (EEI), and sponsoring utilities are collaborating to:

1. Develop a consistent set of short duration, customer interruption cost (CIC) survey questions, including supplemental questions to understand customer behavior during widespread, longer duration interruptions
2. Coordinate administration of CIC surveys to ensure survey results, collectively, will be statistically representative for all U.S. regions and customer classes
3. Update ICE Calculator with new CIC information as well as other suggested improvements to its design/performance

Organization	Roles and Responsibilities
Berkeley Lab + subcontractors	• Develop survey instrument and survey administration protocols • Conduct pre-testing and administer survey • Process CIC survey data • Upgrade ICE Calculator with new CIC information and incorporate additional feedback
EEI	• Support coordination of participation by utilities
Sponsoring utilities	• Provide funding • Support survey administration and sampling of customers • Provide additional feedback on ICE Calculator improvements to Berkeley Lab

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Methods for estimating customer interruption costs

Customer Surveys	*Residential – willingness to pay/accept* *Non-residential – estimated direct economic impacts*
Revealed Preference	*Investment in back-up generation* *Business interruption insurance*
Case Studies	*Customer surveys* *Top-down analysis of aggregate economic impacts*
Regional Economic Models	*Top-down analysis of aggregate economic impacts* *Input-output modeling* *Computable partial and general equilibrium (P/CGE) modeling*

Considerations when using customer interruption cost methods to estimate the economic costs of resilience events

Customer Surveys	*Customers may have limited direct experience* *Scenarios must be constructed to frame responses*
Revealed Preference	*Original actions may not have considered resilience* *Differences in ability to pay must be accounted for*
Case Studies	*Opportunities to study actual events are limited* *Findings must be assumed transferable*
Regional Economic Models	*Input-output – cannot consider customer recourse/adaption* *P/CGE – difficult to calibrate; not suited for smaller events*

MI POWER GRID

Making the Most of Michigan's Energy Future

Reconvened Workgroup Meeting:
Distribution Planning Benefit Cost Analysis

Closing Statements

Patrick Hudson
Manager of the Smart Grid Section
Michigan Public Service Commission

November 3, 2021

For more information:

- **MPSC Distribution Planning Docket:** Case Number U-20147
  - MPSC Staff's Electric Distribution Planning Stakeholder Process Report
  - Commission's August 20, 2020 Order
- **Electric Distribution Planning webpage**

Thank You and Please Stay Engaged!

- Thank you for your participation.
- Please stay engaged.
  - Sign up for the listserv if you have not already
    - Go to MI Power Grid Electric Distribution Planning workgroup webpage
    - Scroll to bottom to add email
  - Questions or Concerns
    - Email: Patrick Hudson hudsonp1@michigan.gov

Thank you!