MARYLAND UNIFIED BENEFIT-COST ANALYSIS (UBCA) FRAMEWORK FOR DISTRIBUTED ENERGY RESOURCES: PHASE II (MARYLAND PSC – CASE NO. 9674)

Part 1: UBCA Work Group Report to the Commission on Methods for Quantifying Impacts in Maryland's UBCA Test and Associated Implementation Recommendations

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1. EXECUTIVE SUMMARY

This report is prepared for the Maryland Public Service Commission ("Commission") by the consultant team to the Unified Benefit-Cost Analysis ("UBCA") Work Group ("Consultant Team") in response to the Commission's direction in Order No. 91424[1] establishing a Phase II process to address the implementation of the UBCA framework adopted Case No. 9674.

Chapter 2 presents an overview of the Commission's Phase I and Phase II UBCA processes.

Chapter 3 describes the Phase II process used to develop this report and the recommendations herein, as informed by the UBCA Work Group and a Technical Methods Subgroup ("TMS" - a large subset of the UBCA Work Group), in large part through a series of technical meetings from September 2025 to March 2026. Chapter 3 also presents several recommended modifications to the Maryland UBCA Test ("MD-UBCA Test") framework adopted in Phase I.

Chapter 4 presents detailed recommendations for methods that may be used to estimate more than two dozen impacts included in the MD-UBCA Test. The chapter also addresses the expected timeline by which each recommended method could be universally applied to DER BCAs in the state – immediate, medium-term (6-12 months), or longer-term (2-3 years) – and provides recommendations for interim approaches where immediate implementation is not feasible. The chapter summarizes key considerations, stakeholder feedback, and areas of consensus and non-consensus.

Tables ES-1, ES-2 and ES-3 below summarize the methods recommended in Chapter 4 for estimating MD-UBCA Test impacts, i.e., electric utility and gas utility system impacts, other fuel impacts, host customer impacts, and various societal impacts. Each table identifies:

- The relative importance of each impact to DER cost-effectiveness determinations
- The level of cost and effort required to apply the recommended method, and
- The expected timeline for statewide implementation.

Chapter 4 also establishes the distinction between system-wide and locational (project specific) analysis. Subsection 4.2.4 distinguishes three scenarios:

- System-wide DER initiatives,
- Targeted but not project-specific DER initiatives, and
- Non-wires solutions ("NWS") or non-pipe solutions ("NPS") in specific locations.

The calculation methods recommended for the first two scenarios are intended to ultimately be consistently applied across all utilities. The third scenario—involving project-specific locations—is methodologically distinct. It requires project-specific inputs (e.g., the specific capital investment being deferred, the specific deferral period, the specific revenue requirement stream over the relevant horizon), and depends on grid topology, DER siting, dispatch capability, and capability characteristics that are inherently location-specific. These project-specific values would need to be added to all applicable system-wide average impacts (with no overlap – each impact category would only be counted once) that would

[1] Issued November 2, 2024.

result from the DER program or project, to sum to a complete BCA. These distinctions are further discussed in Subsection 4.2.4.

Tables ES-4, ES-5 and ES-6 summarize UBCA Work Group positions – consensus, partial agreement or non-consensus[2] – on the recommended methods. These methods were reviewed by the TMS and then shared with the full UBCA Work Group and members of other DER-related work groups who were given an opportunity to review draft and final draft versions of this report before submission to the Commission.

Chapter 4 provides detailed stakeholder positions on all recommended methods. Note that:

- Staff supports the positions of the EmPOWER EAG IE on the proposed UBCA methods herein.
- Potomac Edison and SMECO[3] abstain on all recommendations made in this report.
- Columbia Gas is aligned with all consensus recommendations specified in this report.

Additional detail on TMS and UBCA Work Group discussions related to the methods specified in Chapter 4, including stakeholder comments, meeting notes, and meeting slides, is provided in the Appendices to this report.

[2] The methods for electric and gas "Direct Utility Costs to Promote DERs" are characterized as "likely" consensus because, while no explicit support was provided, stakeholders did not object to the characterization of this recommendation as consensus during review of this report.

[3] SMECO recognizes and appreciates the significant work that has gone into preparing the final draft report. At the same time, SMECO is concerned about the incremental cost associated with their organization performing benefit-cost analyses under the MD-UBCA Test due to customer-member affordability concerns. SMECO is also concerned about the use of societal-based factors to prove cost-effectiveness of an investment, as SMECO believes this may tend to support over-investment in some areas. (Here, the Consultant Team notes that the MD-UBCA secondary tests do not include societal impacts to address this type of concern). In addition, SMECO is very concerned about a universal requirement to undertake a robust cost-effectiveness evaluation under the UBCA for every electric system investment, as SMECO has limited resources to perform such evaluations on a regular basis.

Table ES- 1. Summary of Recommendations for Electric Utility System Impacts

Impact Type	UBCA Recommended Method	Relative Importance when Assessing DER Cost-Effectiveness: EE	DR	DG	DS	EV	BE	Cost / Effort Required by Recommended Method	Implementation Timeline for Recommended Method	Interim Method (for methods that cannot be implemented immediately)	Report Section
Generation Capacity	Power System Modeling (PSM)	**High**						$$$	Long-Term	Either (A) EmPOWER Assumptions; or (B) Values Derived from NLR Cambium.	4.2.1
Energy Generation	Power System Modeling (PSM)	**H**	L	**H**	L	**H**	**H**				
Env. / RPS Compliance	Embedded in energy/capacity costs	Embedded above									
Market Price Effects (energy & capacity)	Analysis of price/demand relationship using either: (A) recent market price data; or (B) PSM outputs	**H**	L	**H**	L	**H**	**H**	$$	**Energy**: Immediate **Capacity**: Medium term	**Capacity**: assume zero	4.2.2
Transmission Capacity	Ratio of Cost to Load Growth (using PJM RTEP data) for average system impacts; or project-specific values for non-wires solutions	Medium						$$	**System-wide:** Medium Term **NWS:** Immediate	EmPOWER Assumptions for system-wide impacts	4.2.3
Distribution Capacity	Ratio of Cost to Load Growth (using utility Distr. data) for system-wide and targeted, but not site-specific, DER initiatives; or project-specific values for non-wires solutions	**High**						$$ / $$$	**System-wide and targeted:** Medium Term **NWS:** Immediate	EmPOWER Assumptions for system-wide and targeted impacts	4.2.4
Distribution O&M	Recommend treating as "not material", so no recommended methodology.	NM						NA	NA	NA	4.2.5
Transmission & Distribution System Losses	(A) statistical analysis of marginal relationship between losses and load; ***or*** (B) default multipliers of readily available average annual energy loss rates	Medium/Low						$	Immediate	NA	4.2.6
Ancillary Services	Historic price approach - but applied only for DERs assumed to be bid into PJM; otherwise assumed to be "not material"	NM	L	L	M	NM	NM	$	Immediate	NA	4.2.7
Risk	Adder = 10% for all electric system benefits for all DERs, except DR (5%). *Values are negative for electrification*	Medium / Low						$	Immediate	NA	4.2.8
Reliability	Application of LBNL ICE calculator	Medium / Low						$$ / $	Immediate	NA	4.2.9
Resilience	None required. Optional analysis of customer "stated preferences" for DERs expected to produce large benefits beyond reliability.	Low						$$	Immediate	NA	4.2.10
Credit & Collection Costs	2% of forecast energy bill savings from major DERs delivered to low-income customers	L	NM	L	NM	L	L	$	Immediate	NA	4.2.11
Utility $ to Promote DERs	Costs as forecast or incurred for incentives, direct investment, program admin, utility performance incentives, etc.	**High**						$	Immediate	NA	4.2.12

Table ES- 2. Summary of Recommendations for Gas Utility System Impacts

<table>
<tr><th rowspan="2">Impact Type</th><th rowspan="2">UBCA Recommended Method</th><th colspan="3">Relative Importance when Assessing DER Cost-Effectiveness</th><th rowspan="2">Cost / Effort Required by Recommended Method</th><th rowspan="2">Implementation Timeline for Recommended Method</th><th rowspan="2">Interim Methodology (for methods that cannot be implemented immediately)</th><th rowspan="2">Report Section</th></tr>
<tr><th>EE</th><th>DR</th><th>BE</th></tr>
<tr><td>Energy</td><td>Henry Hub + Basis, with basis values derived from 3 years of historic differences between Henry Hub costs and delivered cost to distribution system</td><td colspan="3" rowspan="3">High</td><td rowspan="3">$$ / $</td><td rowspan="3">Immediate</td><td rowspan="3">NA</td><td rowspan="3">4.3.1</td></tr>
<tr><td>Transmission Pipeline Capacity</td><td>Embedded in approach to Energy</td></tr>
<tr><td>Env. Compliance</td><td>Embedded in Energy costs</td></tr>
<tr><td>Market Price Effects</td><td>Recommend treating as "not material", so no recommended methodology.</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.2</td></tr>
<tr><td>Distribution Local Delivery Capacity</td><td>Ratio of Cost to Load Growth (using utility Distribution data). Analysis only of areas forecast to experience growth, with results then weighted with zero value to rest of system for average system-wide impact; project-specific values for non-pipe solution (NPS).</td><td colspan="3">Low</td><td>$$ / $$$</td><td>System-Wide:
Medium Term
NPS:
Immediate</td><td>Assume zero impact for system-wide impact</td><td>4.3.3</td></tr>
<tr><td>T&D (‘Pipeline’ & ‘Local Delivery Line’) Losses</td><td>Recommend treating as "not material", so no recommended methodology.</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.4</td></tr>
<tr><td>Risk</td><td>Adder = 10% for gas system benefits for all efficiency and electrification; 5% for DR.</td><td colspan="3">Medium / Low</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.5</td></tr>
<tr><td>Reliability and Resilience</td><td>Recommend treating as “not material”, so no recommended methodology</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.6</td></tr>
<tr><td>Credit & Collection Costs</td><td>Adder equal to 2% of forecast energy bill savings from major DERs delivered to low-income customers</td><td>L</td><td>NM</td><td>L</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.7</td></tr>
<tr><td>Utility $ to Promote DERs</td><td>Costs as forecast or incurred for incentives, direct investment, program admin, utility performance incentives, etc.</td><td colspan="3">High</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.8</td></tr>
</table>

Table ES-3. Summary of Recommendations for Host Customer, Other Fuel, GHG and Other Environmental Impacts

<table>
<tr><th rowspan="2">Impact Type</th><th rowspan="2">UBCA Recommended Method</th><th colspan="6">Relative Importance when Assessing DER Cost-Effectiveness</th><th rowspan="2">Cost / Effort Required by Recommended Method</th><th rowspan="2">Implementation Timeline for Recommended Method</th><th rowspan="2">Interim Methodology (for methods that cannot be implemented immediately)</th><th rowspan="2">Report Section</th></tr>
<tr><th>EE</th><th>DR</th><th>DG</th><th>DS</th><th>EV</th><th>BE</th></tr>
<tr><td rowspan="3">Host Customer Impacts</td><td rowspan="3">Mix of research + proxy adders. 3-step process recommended to:
(A) identify material non-energy impacts (NEIs) for each DER;
(B) monetize (i) customer measure costs; (ii) tax credits; (iii) O&M costs; (iv) water costs;
(C) adopt proxy adders and/or specific values based on research/analysis</td><td colspan="6">Costs:
High</td><td rowspan="3">$$ / $</td><td rowspan="3">(A) Immediate
(B) Immediate
(C) Medium-Term</td><td rowspan="3">Assume zero impact for (C) for anything other than customer measure costs, tax credits, O&M cost and water costs.</td><td rowspan="3">4.5</td></tr>
<tr><td colspan="6">Benefits:</td></tr>
<tr><td>M/L</td><td>L</td><td>L</td><td>L</td><td>M/L</td><td>M/L</td></tr>
<tr><td>Other Fuels</td><td>Forecasts of other fuel prices:
(A) EIA reference for current prices for building fuels (propane/fuel oil) and transportation fuels (gasoline/diesel);
(B) EIA AEO regional forecast to escalate prices into future years</td><td>M</td><td>L</td><td>L</td><td>NA</td><td>H</td><td>H</td><td>$</td><td>Immediate</td><td>NA</td><td>4.4</td></tr>
<tr><td>Greenhouse Gas Emissions</td><td>Two key parts:
(A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels;
(B) Social Cost Carbon to translate emission impacts to $</td><td>H</td><td>NM</td><td>H</td><td>NM</td><td>H</td><td>H</td><td>$$$</td><td>Electric:
(A) Long-Term
(B) Immediate
Gas/Other Fuels:
(A) Immediate
(B) Immediate</td><td>For Electric (Part A): Either EmPOWER assumptions or Values from NLR Cambium for Electric</td><td>4.6.1</td></tr>
<tr><td>Other Environmental / Public Health (Criteria Pollutants)</td><td>Two key parts:
(A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels;
(B) EPA COBRA to translate emission impacts to $</td><td>M</td><td>L</td><td>M</td><td>NM</td><td>H</td><td>M</td><td>$$$</td><td>Electric:
(A) Long-Term
(B) Immediate
Gas/Other Fuels:
(A) Immediate;
(B) Immediate</td><td>For Electric (Part A): Either EmPOWER assumptions or Extrapolation from GHG values from NLR Cambium for Electric</td><td>4.6.2</td></tr>
<tr><td>Societal Resilience</td><td>Defer to future - recommend separate workgroup process to identify appropriate key metrics and methodological recommendation</td><td>NA</td><td>NA</td><td colspan="2">Med/Low</td><td>NA</td><td>NA</td><td>$$</td><td>Medium to Long-Term</td><td>Qualitative Assessment only</td><td>4.6.3</td></tr>
</table>

Table ES-4. Summary of Recommendations for Electric Utility System Impacts

Impact Type	UBCA Recommended Method	Level of Agreement*
Generation Capacity *Subsection 4.2.1*	Power System Modeling (PSM)	Partial Agreement
Energy Generation *Subsection 4.2.1*	Power System Modeling (PSM)	
Environmental / RPS Compliance *Subsection 4.2.1*	Embedded in energy/capacity costs determined using PSM	
Market Price Effects *Subsection 4.2.2*	Analysis of price/demand relationship using either: (A) recent market price data; or (B) PSM outputs	Partial Agreement
Transmission Capacity *Subsection 4.2.3*	Ratio of Cost to Load Growth (using PJM RTEP data)	Partial Agreement
Distribution Capacity *Subsection 4.2.4*	Ratio of Cost to Load Growth (using utility Distr. data)	Partial Agreement
Distribution O&M *Subsection 4.2.5*	None required. Not considered material.	Consensus
T&D Losses *Subsection 4.2.6*	(A) statistical analysis of marginal relationship between losses and load; ***or*** (B) default multipliers of readily available average annual energy loss rates	Partial Agreement
Ancillary Services *Subsection 4.2.7*	Historic price approach - but applied only for DERs assumed to be bid into PJM; otherwise assumed to be "not material"	Consensus
Risk *Subsection 4.2.8*	Adder = 10% for all electric system benefits for all DERs, except DR (5%). *Values are negative for electrification*	Partial Agreement
Reliability *Subsection 4.2.9*	Application of LBNL ICE calculator	Non-Consensus
Resilience *Subsection 4.2.10*	None required. Optional analysis of customer "stated preferences" for select DER investments expected to produce significant benefits beyond reliability.	Consensus
Credit & Collection Costs *Subsection 4.2.11*	Adder equal to 2% of forecast energy bill savings from major DERs delivered to low-income customers	Consensus
Utility $ to Promote DERs *Subsection 4.2.12*	Costs as forecast or incurred for incentives, direct investment, program admin, utility performance incentives, etc.	Likely Consensus

* Consensus = Agreement among stakeholders, with no disagreement, on all aspects of the methodology.
Partial Agreement = Agreement among stakeholders on certain aspects of the methodology, but not all aspects.
Non-Consensus = One or more stakeholders do not agree with the overarching methodology.

Table ES- 5. Summary of Recommendations for Gas Utility System Impacts

Impact Type	UBCA Recommended Method	Level of Agreement*
Energy *Subsection 4.3.1*	Henry Hub + Basis, with basis values derived from 3 years of historic differences between Henry Hub costs and delivered cost to distribution system	Partial Agreement
Transmission Pipeline Capacity *Subsection 4.3.1*	Embedded in approach to Energy	
Env. Compliance *Subsection 4.3.1*	Embedded in Energy costs	
Market Price Effects *Subsection 4.3.2*	Recommend treating as "not material", so no recommended methodology.	Consensus
Distribution Capacity *Subsection 4.3.3*	Ratio of Cost to Load Growth (using utility Distribution data). Analysis only of areas forecast to experience growth, with results then weighted with zero value to rest of system.	Non-Consensus
T&D Losses *Subsection 4.3.4*	Recommend treating as "not material", so no recommended methodology.	Consensus
Risk *Subsection 4.3.5*	Adder = 10% for gas system benefits for all efficiency and electrification; 5% for DR.	Consensus
Reliability & Resilience *Subsection 4.3.6*	Recommend treating as “not material”, so no recommended methodology.	Consensus
Credit & Collection Costs *Subsection 4.3.7*	Adder equal to 2% of forecast energy bill savings from major DERs delivered to low-income customers	Consensus
Utility $ to Promote DERs *Subsection 4.3.8*	Costs as forecast or incurred for incentives, direct investment, program admin, utility performance incentives, etc.	Likely Consensus

* Consensus = Agreement among stakeholders, with no disagreement, on all aspects of the methodology.
Partial Agreement =Agreement among stakeholders on certain aspects of the methodology, but not all aspects.
Non-Consensus = One or more stakeholders do not agree with the overarching methodology.

Table ES-6. Summary of Recommendations for Non-Utility System Impacts

Impact Type	UBCA Recommended Method	Level of Agreement*
Host Customer Impacts *Section 4.5*	Mix of research + proxy adders. 3-step process: (A) identify material NEIs for each DER; (B) monetize (i) customer measure costs; (ii) tax credits; (iii) O&M costs; (iv) water costs; (C) adopt proxy adders and/or specific values based on research/analysis	Consensus
Other Fuels *Section 4.4*	Forecasts of other fuel prices: (A) EIA reference for current prices for building fuels (propane/fuel oil) and transportation fuels (gasoline/diesel); (B) EIA AEO regional forecast to escalate prices into future years	Consensus

Impact Type	UBCA Recommended Method	Level of Agreement*
Greenhouse Gas Emissions *Subsection 4.6.1*	Two key parts: (A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels; (B) Social Cost Carbon to translate emission impacts to $	Partial Agreement
Other Environmental / Public Health (Criteria Pollutants) *Subsection 4.6.2*	Two key parts: (A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels; (B) EPA COBRA to translate emission impacts to $	Partial Agreement
Societal Resilience *Subsection 4.6.3*	Defer to future - recommend separate workgroup process to identify appropriate key metrics and methodological recommendation	Consensus

* Consensus = Agreement among stakeholders, with no disagreement, on all aspects of the methodology.
Partial Agreement =Agreement among stakeholders on certain aspects of the methodology, but not all aspects.
Non-Consensus = One or more stakeholders do not agree with the overarching methodology.

Chapter 5 describes coordination with the Commission's other DER-related workgroups, including the EmPOWER Maryland Evaluation Advisory Group (EmPOWER EAG), Maryland Energy Storage Program Work Group (MESP WG), PC44 Electric Vehicle Work Group (PC44-EV WG), and Electric System Planning Work Group (ESP WG) (collectively, "Other WGs"), in developing the recommended MD-UBCA Test methods. Chapter 5 also provides guidance regarding the applicability of the MD-UBCA Test methods to the different DERs and use cases covered by each work group and recommends implementation timelines based on each work group's schedule and scope. Table ES-7 summarizes the applicability of the MD-UBCA Test and proposed methods to each work group's scope.

Table ES-7. Applicability of MD-UBCA Test to Other WGs' Scope

Work Group Scope	MD-UBCA Test and Methods Applicable?
EmPOWER Programs *EmPOWER EAG*	Yes, where impacts are relevant and material to EmPOWER related DERs and subject to statutory requirements for basing goals on MDE forecasts.
MESP Strategies *MESP WG*	Yes, where impacts are relevant and material to distribution storage resources.
Energy Storage Procurement *MESP WG*	Yes, where impacts are relevant and material to distribution and transmission-connected storage resources.
PC-44 Electric Vehicle Programs *PC44-EV WG*	Yes, where impacts are relevant and material to EV managed charging programs and pricing strategies.
Electric System Plans *ESP WG*	Depends on the investment type.

Finally, Chapter 6 presents considerations for a future process to implement and maintain the MD-UBCA Test and associated methods for estimating impacts.[4] Although still under discussion by the UBCA Work Group, the process that is eventually proposed may serve the following purposes:

a) Overseeing and coordinating implementation of the Commission's ultimate decisions on recommended methods and timelines across Other WGs to support standardized approaches;
b) Conducting any new or updated studies to support estimation of MD-UBCA Test impacts;
c) Coordinating utilities and other stakeholders to support Commission engagement with other state agencies in the potential use of the power system modeling approach by the future Strategic Energy Planning Office (see discussion in Subsection 4.2.1); and
d) Preparing recommendations to the Commission on any needed changes to the MD-UBCA Test on a periodic basis and whenever relevant new policy directives or laws are enacted, as applicable.

Summary of Recommendations

Where consensus exists, the UBCA Work Group recommends adoption of the methods described in Chapter 4. Stakeholders have agreed that UBCA Work Group consensus in this report is defined as explicit agreement from stakeholders who commented on a method and no disagreement from any stakeholder.

The UBCA Work Group also recommends that consensus "immediate" methods – and interim methods where needed – be implemented going forward for all BCAs being conducted for DER investment, subject to Commission discretion and as consistent with the schedules laid out in Chapter 5.

For methods with partial-agreement or non-consensus, the Commission may wish to (a) direct use of the Consultant Team's recommended method, (b) direct use of a different method, based on stakeholder positions, or (c) request additional information and/or proposals via written comments from stakeholders.

The UBCA Work Group Leader further recommends that the Commission require the assumptions and procedures supporting BCAs to be clearly documented such that calculations are understandable and replicable.

In the forthcoming Part 2 report of this UBCA Phase II process, the UBCA Work Group anticipates providing further recommendations regarding:

1) A process that may be established to coordinate implementation and to support development of medium-term and long-term methods, and
2) Guidance for conducting distributional equity, economic development, and rate and bill impact analyses.

[4] as directed by Commission Order No. 91424.

2. BACKGROUND - UBCA PHASE I AND PHASE II

2.1. UBCA PHASE I OVERVIEW

On May 13, 2022, the Maryland Public Service Commission ("Commission") issued Order No. 90212 in Case No. 9674, establishing the intent to develop a common framework for assessing the cost-effectiveness of all distributed energy resources ("DERs"). The Commission noted that cost-benefit analyses before the Commission up to that point had been "idiosyncratic," involving the application of different tests across DER types, potentially leading to inconsistent results.[5] By establishing this common framework, the Commission aimed to eliminate these inconsistencies that might lead to overstatement or understatement of the relative cost-effectiveness and therefore potential over- or under-investments in some DERs.[6] Order No. 90212 also established a new Unified Benefit-Cost Analysis (UBCA) Work Group ("the UBCA Work Group") to develop a primary Maryland-specific UBCA test based on the principles of the *National Standard Practice Manual for Benefit Costs Analysis of Distributed Energy Resources* (NSPM, 2020).

Between July 2023 and April 2024, the UBCA Work Group, led by a Commission Advisor Work Group Leader, engaged in a collaborative, eight-meeting process with participation from Maryland state agencies, Maryland electric and gas utilities, EmPOWER evaluation consultants, and non-profit organizations. A consultant team was retained by the Commission to facilitate the Work Group process and to serve as technical experts.[7] Through a process of virtual polling, homework assignments, subgroup deep-dives, and iterative draft reviews, the Work Group identified the specific impacts to be included in the primary MD-UBCA Test and secondary tests (see Table 1 and Table 2 below). The final Phase I report, filed in May 2024, put forth recommendations which were largely reached by consensus and incorporated NSPM guidance, stakeholder input, Maryland policy direction, existing Maryland BCA practices, and BCA practices of other states.

The final UBCA Phase I Report recommended:

- **A primary MD-UBCA Test** consisting of a categorized list of impacts to be calculated (both benefits and costs). The purpose of the development and eventual implementation of the primary MD-UBCA Test is to inform stakeholders as to whether a proposed DER investment or strategy is likely to increase or decrease the cost of meeting utility system needs while achieving applicable energy policy goals (relative to a 'do-nothing' scenario or to alternative DER investments or strategies).
- **Two secondary tests**—the Utility Cost Test (UCT) and Total Resource Cost (TRC) test—developed to help inform (a) decisions in cases where a DER investment might only marginally pass or fail the primary test, (b) prioritization of DER investments, or (c) decisions on how much funding should be provided to a DER program or strategy.

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[5] Maillog No. 240668, Case No. 9674, Unified Benefit Cost Analysis Framework for Distributed Energy Resources [para. 19 of the Order]
[6] *Id.* [para. 20 of the Order]
[7] The consultant team in UBCA Phase I was led by the prime contractor E4TheFuture and included other subcontractors. Consultants were retained via an Exelon contract overseen by Commission staff.

- **Guidance for applying the MD-UBCA Test**, e.g., discount rates, BCA assessment level, geographic boundaries, and application across different contexts.
- **Initiation of a Phase II process** to support implementation of the primary and secondary tests, focusing on development of the methods needed to quantify each impact, and to provide guidance on conducting complementary analyses identified in the Phase I Report.

Table 1 and Table 2 below summarize the primary MD-UBCA Test and secondary tests as they were proposed in the Phase I Report,[8] organized by electric utility system impacts, gas utility system impacts, other fuel impacts, host customer impacts, and societal impacts.[9]

Table 1: Primary Maryland UBCA Test – Summary

Impact Category	Impact Sub-Category	Specific Impacts	Included in Test?
Utility System	Electric or Gas	All	✓
Non-Utility System	Other Fuels	Gas Utility Impacts from Electric DERs	✓
		Electric Utility Impacts from Gas DERs	
		Other Fuel Impacts (Propane, Gas, etc.)	
	Host Customer	All	✓
	Societal	Greenhouse Gas Emissions	✓
		Other Environmental	✓
		Public Health	✓
		Resilience	✓
		Energy Security	✓

Table 2: Maryland Secondary BCA Tests – Summary

Impact Category	Impact Sub-Category	Specific Impacts	Included in Test? TRC	Included in Test? UCT
Utility System	Electric or Gas	All	✓	✓
Non-Utility System	Other Fuels	Gas Utility Impacts from Electric DERs	✓	-
		Electric Utility Impacts from Gas DERs		-
		Other Fuel Impacts (Propane, Gas, etc.)		-
	Host Customer	All	✓	-
	Societal	Greenhouse Gas Emissions	-	-
		Other Environmental	-	-
		Public Health	-	-
		Resilience	-	-
		Energy Security	-	-

2.2. UBCA PHASE II OVERVIEW

On November 22, 2024, the Commission issued Order No. 91424[10] which largely approved the UBCA Work Group's Phase I framework recommendations and established a Phase II process

[8] From Table 16 and Table 17 in Maryland PSC - Case No. 9674. *Maryland Unified Benefit-Cost Analysis (UBCA) Framework for Distributed Energy Resources*, Work Group Report, May 16, 2024.

[9] Note that several proposed changes to the UBCA Test presented in the UBCA Phase I report are addressed in Chapter 3 of this report.

[10] Maillog No. 313783, Case No. 9674, Unified Benefit Cost Analysis Framework for Distributed Energy Resources. November 22, 2024.

to address implementation of the framework. The Commission found that the primary MD-UBCA Test (and supporting secondary tests) "were developed through a detailed, collaborative process, and that utilization of the [same BCA tests] would be beneficial to ensure that all DERs are assessed in a consistent manner against each other and alternatives, thereby increasing transparency and efficiency in the evaluation process, as well as optimizing investments in DERs."[11] The Commission approved, in principle, the framework put forth in the Phase I Report, noting that it will need to be implemented across Maryland's DER proceedings and that "the nuances of the framework may require modification during the implementation phase."[12]

In Order No. 91424, the Commission also supported the UBCA Work Group's recommendation to initiate a Phase II process to support implementation of the primary MD-UBCA Test and secondary tests. The Order identified the following tasks for the reconvened UBCA Work Group:

1. **Identify appropriate methods** to account (monetarily or otherwise quantifiably) for DER impacts included in the MD-UBCA Test. When recommending methods, the Work Group should weigh the benefit of developing an input against the cost to develop said input.
2. **Coordinate with the Commission's other existing work groups** where cost-effectiveness testing has been previously developed, including the EmPOWER Maryland Evaluation Advisory Group ("EmPOWER EAG"), Electric Vehicle Work Group ("PC44-EV WG"), Maryland Energy Storage Work Group ("MESP WG"), and Electric System Planning Work Group ("ESP WG"). In coordination with these other DER-related Work Groups (collectively, "Other WGs"), the UBCA Work Group and a consultant team ("Consultant Team") will:
    a. Evaluate existing BCA practices against the UBCA report recommendations and determine what should or should not change, and
    b. Determine the process for implementing, and implement, the MD-UBCA Test across the DERs and utility investments.
3. **Develop and propose processes and procedures to maintain the primary and secondary tests over time** and periodically reassess the tests every four years (or more often at the Commission's discretion) to ensure that the tests are keeping with their intended purpose to account for changing state policy.
4. **Provide guidance on conducting distributional equity analysis** alongside BCAs to inform how DER investments will impact priority populations/communities (e.g., underserved populations) relative to other customers.
5. **Providing guidance on conducting a Maryland economic development analysis** that accounts for net job creation, including direct and potentially indirect jobs.
6. **Providing guidance on conducting rate and bill impact analysis** alongside BCAs to understand equity impacts across customer classes/sectors, including assessing not only the monetary impacts for the rate classes as a whole, but also how various rate designs impact customers with varying consumption rates and patterns.

[11] Maryland Public Service Commission, Order No. 91424
[12] Maryland Public Service Commission, Order No. 91424

The Commission noted in its Order that the Phase II process should prioritize what is listed as task one above. Task two above, Other WG coordination, is necessary to properly completing task one and is generally important throughout the Phase II process.

Accordingly, this Phase II "Part 1 Methods Report" focuses on tasks one and two. A separate report ("Part 2 Report"), which the Commission may expect in early fall, 2026, will address tasks three through six.

The Consultant Team—led by Energy Futures Group with subcontractors from E4TheFuture (now NASEO) and Rábago Energy—was selected to support the Phase II process.[13] The Consultant Team has moderated development of methods and other recommendations in this report in consultation with the UBCA Work Group Leader.

[13] The Commission's Order 91424 directed Exelon to work with the Commission to either re-engage the Phase I consultant team (led by E4TheFuture) or to initiate a new RFP process to retain a consultant for Phase II. A decision was made to select the Phase I team, this time led by Energy Futures Group and subcontracting to E4TheFuture (E4) and Rábago Energy. Note that E4 staff transitioned (along with NESP – a project of E4) to the National Association of State Energy Officials (NASEO) on Jan 1, 2026. Phase II work group meetings thereafter referred to E4 staff as NASEO staff. In addition, Rábago Energy played an initial small role in providing project technical support, but ultimately the Consultant Team was comprised of Energy Futures Group and NASEO staff only.

3. UBCA PHASE II WORK GROUP PROCESSES

3.1. WORKGROUP ENGAGEMENT AND PARTICIPANTS

The Phase II process has involved several levels of engagement with Maryland stakeholders to address the Commission's direction in Order No. 91424. This engagement included:

- Convening the **UBCA Work Group** – largely the same organizations that participated in Phase I – to launch the Phase II effort and later to present the findings and recommendations of this report;
- Forming a **Technical Methods Subgroup** ("TMS") to inform the detailed development of methods through a series of technical meetings; and
- Coordinating with **other Maryland DER-related work groups** ("Other WGs") to review their existing BCA practices and to understand their perspectives on implementation timelines and processes for applying the MD-UBCA Test and recommended methods developed through the TMS.

The UBCA Work Group convened for a kick-off meeting on a July 14, 2025. At this meeting, the Consultant Team provided an overview of the Phase I process, the MD-UBCA Test and secondary tests supported by the Commission in Order No. 91424, and the Commission's directive defining the scope of Phase II.

The Consultant Team also proposed, in consultation with the UBCA Work Group Leader, the formation of a TMS to inform the development of MD-UBCA Test methods, and invited UBCA Work Group members to indicate their interest in and availability to participate in a series of technical meetings.

The Consultant Team also invited TMS participation from members of the Other WGs during presentations to these WGs in summer 2025. At these presentations, in addition to inviting TMS participation, the Consultant Team provided an overview of the Phase II scope and process, presented the Team's understanding of the existing or evolving BCA practices within each work group, and reviewed coordination strategies to align with the UBCA Phase II process. Additional details on inter-Work Group coordination are provided in Section 3.4.

Active UBCA Work Group participants include representatives from a range of state agencies, utilities, and other organizations as shown in Table 3. All listed organizations had at least one representative on the TMS.

Table 3. UBCA Phase II Work Group

UBCA Phase II Work Group
Maryland Commission Technical Staff*
Maryland Office of People's Council (OPC) (with consultant Synapse Energy Economics)
Maryland Energy Administration
Columbia Gas
Joint Maryland Exelon Utilities ("JMEU") with consultants from Brattle Group • Baltimore Gas and Electric ("BGE") • Pepco Holdings, Inc. ("PHI")
Potomac Edison
Southern Maryland Electric Cooperative ("SMECO")
Washington Gas ("WGL") (with consultant from Energytools, LLC)
Apex Analytics (EmPOWER Statewide Evaluator representing the utilities)
EmPOWER Evaluation Advisory Group (EAG) Independent Evaluators ("IE") • Demand Side Analytics • Hungeling Analytics • KBH Energy Consultant • Loper Energy

The development of the MD-UBCA Test methods occurred within the TMS over a series of meetings held between September 2025 and March 2026. Section 3.2 describes the TMS process in more detail.

3.2. TECHNICAL METHODS SUBGROUP (TMS) PROCESS

The Consultant Team held 14 meetings with the TMS, each scheduled for two hours. In the first meeting, the Consultant team outlined the key objectives of the TMS process:

- **Prioritize impacts** to address within the MD-UBCA Test.
- **Review methods** currently used in Maryland to estimate impacts as well those presented in the National Energy Screening Project's *Methods, Tools, and Resources Handbook* ("MTR Handbook") and other resources.
- Address key methodological parameters, including:
  - Suitability across DER types and use cases
  - Data availability and sources
  - Required level of granularity
  - Forecasting assumptions
  - Challenges, costs, and effort associated with developing input values (to inform prioritizing and recommended research areas)
- **Develop standard syntax** for presenting and describing methods for each impact.
- **Prepare recommendations for methods**, document any areas of non-consensus, and present to the UBCA Work Group (and Other WGs) for feedback, in consultation with the UBCA Work Group Leader.

During the initial TMS meeting, the Consultant Team also presented a comparison of the MD-UBCA Test against existing BCA tests used by Other WGs—particularly the EmPOWER EAG and the PC44-EV WG, where formal BCA tests already exist. This comparison exercise, presented in Section 3.3, helped identify the priority impacts on which to focus the Phase II process, which, in turn, informed the schedule for addressing all MD-UBCA Test impacts.

A summary of the fourteen[14] TMS meetings and agendas is provided in Table 4.

Table 4. Technical Methods Subgroup Meetings and Agenda

Date	Agenda Items
Sept 30, 2025 (Meeting 1)	• Review existing BCA tests in Maryland and identify gaps in DER impacts addressed; • Review the list of MD-UBCA Test impacts and Consultant Team proposed priorities for developing methods for subgroup feedback; • Review the proposed schedule of TMS meetings
Oct 17, 2025 (Meeting 2)	• Review reported methods and recommended approached for Electric Energy, Capacity, and Market Price Effects
Nov 3, 2025 (Meeting 3)	• Review and discuss recommended approaches for Electric Energy and Capacity, and Market Price Effects; • Review reported and standard methods for Electric Transmission and Distribution (T&D) Capacity, and Electric T&D Line Losses
Nov 10, 2025 (PSM Follow-up Meeting)	• Provided more detailed insight into Power Systems Modeling (PSM) approach, including a cost and timeframe overview; and discussed group alignment on different approaches and clarified any remaining questions
Nov 21, 2025 (Meeting 4)	• Review and discuss preliminary recommended approaches for Electric T&D Capacity and T&D Line Losses; • Review reported and standard methods for Gas Energy and Capacity
Dec 8, 2025 (Meeting 5)	• Polling on formal recommendations for Energy Market Price Effects, Electric T&D Capacity, and Electric T&D Line Losses; • Preliminary Recommendation for Gas Energy/Commodity and Gas T&D; • Review of methodological options for Electric Reliability and Resilience
Dec 18, 2025 (Meeting 6)	• Polling on formal recommendations for Power System Modeling for Electric Energy and Capacity
Jan 8, 2026 (Meeting 7)	• Review polling results on formal recommendations for Electric Energy and Capacity, Market Price Effects, T&D Capacity, and T&D Line Losses; • Polling on formal recommendations for Gas Energy/Commodity and Gas T&D; • Review of methodological options and preliminary recommendations for Electric Reliability and Resilience and Greenhouse Gas (GHG) Emissions
Jan 23, 2026 (Meeting 8)	• Review polling results on formal recommendations for Gas Energy/Commodity and Gas Distribution Capacity; • Polling on formal recommendations for Electric Reliability and Resilience and Societal GHG Emissions; • Review of methodological options and preliminary recommendations for Societal Other Environmental and Public Health Impacts

[14] Table 4 lists Meetings 1–13 (as shown in Appendix A) as well as an added informational meeting on the topic of Power System Modeling which was held on Nov 10, 2025.

Date	Agenda Items
Jan 27, 2026 (Meeting 9)	• Review of methodological options and preliminary recommendations for Electric Risk and Host Customer Impacts
Feb 23, 2026 (Meeting 10)	• Review polling results on formal recommendation for Electric Reliability and Resilience, and GHG Emissions; • Polling on formal recommendations for Electric Risk, Other Environmental and Public Health Impacts, and Host Customer Non-Energy Impacts (NEIs); • Review methodological options and preliminary recommendations for Electric Ancillary Services, and Other Fuels
Mar 9, 2026 (Meeting 11)	• Review polling results on formal recommendations for Electric Risk, Other Environmental/Public Health, and Host Customer NEIs; • Polling on formal recommendations for Electric Ancillary Services; • Review methodological options and preliminary recommendations for Electric and Gas Credit and Collection Costs, and Societal Resilience
Mar 17, 2026 (Meeting 12)	• Review overall Phase II schedule (report drafting, TMS and UBCA work group review) • Review MD-UBCA Test methods implementation timing and priority
Mar 26, 2026 (Meeting 13)	• Review polling results on formal recommendation for Electric Ancillary Services; • Polling on formal recommendations for Other Fuels, Societal Resilience, Electric and Gas Credit and Collection Costs, and Gas Reliability and Resilience

The TMS meetings were used to systematically evaluate each MD-UBCA Test impact. After the first few meetings, the Consultant Team, with TMS feedback, adopted a structured three-step process for TMS input on methods to ensure sufficient time for understanding, discussion, and feedback on each method:

Step 1: Table-Setting
Presentation of best-practice options and a summary of current practice.

Step 2: Preliminary Recommendations
Presentation of initial consultant recommendations, considering any input from table-setting presentations.

- Written feedback was requested and typically provided by key stakeholders (utilities, OPC, EmPOWER EAG Independent Evaluators).

Step 3: Formal Recommendations
Presentation of formal recommendations, considering feedback.

- Presentation included responses to all comments or concerns raised on preliminary recommendations – sometimes modifying recommendation and sometimes not.
- Stakeholders were polled within 10-14 days of presentation. Polls requested (1) support; (2) support with modifications (with specifics); or (3) opposition with alternative recommendations.

In addition to this structured process, the Consultant Team met directly with TMS members, including utility staff, OPC staff and EmPOWER IE representatives, to clarify Consultant Team recommendations and TMS comments and questions.[15]

After each TMS meeting, the Consultant Team distributed meeting notes with key action items via email and maintained a shared Box drive containing all meeting slides, notes, spreadsheets for stakeholder feedback, and survey forms for formal recommendations. The following appendices to this report document the TMS process:

- **Appendix A: Meeting Slides –** slide decks used in UBCA Work Group and TMS meetings.
- **Appendix B: Meeting Notes –** detailed records of TMS discussions.
- **Appendix C: Survey Responses –** feedback collected via Microsoft Forms, documenting the TMS evaluations of each formal recommendation. Note that some stakeholder TMS survey positions may differ from the final positions reflected in Chapter 4 (final positions were confirmed through the report editing process).

Survey responses to the final methods recommendations are discussed in Chapter 4. This chapter also provides details and recommendations for all MD-UBCA Test methods. Section 3.5 summarizes recommendations on the implementation timeline and process, with additional detail provided in Chapter 5.

3.3. PROPOSED CHANGES TO THE MD-UBCA TEST

The TMS reviewed all impacts included in the MD-UBCA Test developed in Phase I and confirmed most Phase I conclusions regarding applicability and materiality. However, upon review and as an initial matter, several modifications to the treatment or characterization of certain MD-UBCA Test impacts as they were originally adopted in Order No. 91424, were proposed by the Consultant Team and supported by the UBCA Work Group, as described below.

Some of these impacts were identified as discrete line items in the MD-UBCA Test in Phase I, but upon further consideration in Phase II, are typically embedded in other impacts, and as such are recommended to be removed as discrete line items. As such, these impacts – namely, electric utility system distribution voltage and societal energy security – are not separately discussed in their own Chapter 4 Subsections.

Certain other impacts previously considered applicable and material for some or all DER types – DER types include energy efficiency (EE), demand response (DR), distributed storage (DS), distributed generation (DG), electric vehicles (EVs) and building electrification (BE) – are proposed to be recharacterized as 'not material' (i.e., not large enough to merit routine inclusion).[16] Importantly, some impacts which are proposed for reclassification as 'not

[15] These discussions focused on the power system modeling method, gas energy costs, and gas distribution capacity costs. Additionally, the Consultant Team reviewed some of EmPOWER's EAG avoided cost spreadsheets to ensure the Consultant Team understood the existing method.

[16] Not material means that a given impact can affect the cost or benefit associated with a particular type of DER, but not a large enough impact to merit routine consideration in benefit-cost analyses.

material' today may become material in the future, as further discussed below and in the relevant impact Subsections in Chapter 4.

Electric Utility System Impacts

The UBCA Work Group recommends that the following electric utility system impacts be recharacterized as follows:

Ancillary services: Modify ancillary services from being characterized as applicable and material to 'Not Material' for EE and BE. As touched on in Subsection 4.2.7, these DERs are not anticipated to meaningfully affect ancillary services markets.

Distribution operation and maintenance (O&M): Modify Distribution O&M from being characterized as applicable and material to 'Not Material' for all DER types. There is little information available on the marginal impacts of DER investments on such costs, and the information that exists suggests such impacts are not material. This conclusion can be revisited if future analyses indicate otherwise.[17] See Subsection 4.2.5 for further discussion.

Distribution voltage: Distribution voltage management and regulation (to the extent material for DERs, which is only the case for DG and storage) is embedded in an electric utility's distribution capital costs (i.e., distribution capacity impact) and operation and maintenance (O&M) activities. As such, the UBCA Work Group recommends that distribution voltage be removed as a discrete impact in the MD-UBCA Test.

[17] This impact was not formally addressed during the TMS process due to time constraints. However, the UBCA Work Group was provided an opportunity to comment during the final draft report comment period.

Table 5. Electric Utility System Impacts – MD-UBCA Test vs Current Maryland Practices

Impact Type	Impact	MD-UBCA Test						EmPOWER BCA	PC44-EV BCA
		EE	DR	DG	DS	EV	BE		
Generation	Energy Generation	✓	✓	✓	✓	✓	✓	✓	✓
	Capacity	✓	✓	✓	✓	✓	✓	✓	✓
	Environmental Compliance	✓	✓	✓	✓	✓	✓	✓	Embedded
	RPS/CES Compliance	✓	NM	✓	NM	✓	✓	✓	✓
	Market Price Effects	✓	✓	✓	✓	✓	✓	✓	✓
	Ancillary Services	*NM*	✓	✓	✓	✓	*NM*	✓	no
Transmission	Transmission Capacity	✓	✓	✓	✓	✓	✓	✓	✓
	Transmission System Losses	✓	✓	✓	✓	✓	✓	✓	✓
Distribution	Distribution Capacity	✓	✓	✓	✓	✓	✓	✓	✓
	Distribution System Losses	✓	✓	✓	✓	✓	✓	✓	✓
	Distribution O&M	*NM*	*NM*	*NM*	*NM*	*NM*	*NM*	no	no
	~~Distribution Voltage~~	Embedded in Other Distribution Impacts						Embedded	Embedded
General	Financial Incentives	✓	✓	✓	✓	✓	✓	✓	✓
	Utility Direct Investments in DERs	✓	✓	✓	✓	✓	✓	✓	✓
	Program Administration	✓	✓	✓	✓	✓	✓	✓	✓
	Utility Performance Incentives**	✓	✓	✓	✓	✓	✓	✓	no
	Credit and Collection	✓	NM	✓	NM	✓	✓	✓	no
	Risk	✓	✓	✓	✓	✓	✓	✓	Embedded
	Reliability & Resilience	✓	✓	✓	✓	✓	✓	✓	no
✓	Both applicable and material								
NM	Not material, i.e., not large enough to merit routine inclusion								

*Source: **Table S-2 and Table 5** in Work Group Report: Maryland Unified Benefit-Cost Analysis Framework for Distributed Energy Resources, Case No. 9674. May 16, 2024. Blue font rows indicate recommended modifications.*

*** For Utility Performance Incentives, new information was provided during the Phase II process that updated or corrected characterization of EmPOWER's accounting for this impact.*

GAS UTILITY SYSTEM IMPACTS

The UBCA Work Group recommends that the following gas utility system impacts be recharacterized from applicable and material to 'Not Material' for all applicable DER types (EE, DR, and BE).

Gas market price effects: Gas market prices are arguably set by national markets, so it is likely that reductions from just Maryland EE, DR and BE programs will not be large enough to materially affect prices. This conclusion can be revisited if future analyses indicate otherwise. See Subsection 4.3.2.

Gas T&D ('pipeline' and 'local delivery line') losses: Unlike electric utility T&D losses which are a direct function of the amount of electricity moving across power lines (i.e., declining as demand declines), gas losses are not a function of throughput. Rather, they are largely a function of system pressure. Though system pressures will vary, gas utilities endeavor to keep pressures within specific, safe ranges throughout the year. Thus, reductions in gas throughput that result from EE, DR, or electrification programs are unlikely to materially affect the magnitude of losses. See Subsection 4.3.4.

Gas reliability and resilience: Unlike electric utilities, gas utilities plan capital investments in the distribution system to meet truly extreme weather conditions (e.g., conditions that may be experienced only once every 50 years). In that context, it is unlikely that there are material opportunities for improving reliability and resilience beyond what would already be captured in avoided distribution system capacity costs. See Subsection 4.3.6.

Table 6. Gas Utility System Impacts – MD-UBCA Test vs Current Maryland Practices

Impact Type	Impact	MD-UBCA Test			EmPOWER BCA
		EE	DR	BE***	
Energy	Fuel & Variable O&M	✓	✓	✓	✓
	Capacity and Storage	✓	✓	✓	*
	Environmental Compliance	✓	NM	✓	✓
	Market Price Effects	*NM*	NM	*NM*	✓
Transmission	Pipeline Capacity	✓	✓	✓	*
	Pipeline Losses	*NM*	*NM*	*NM*	✓
Distribution	Local Delivery Capacity	✓	✓	✓	*
	Local Delivery Line Losses	*NM*	*NM*	*NM*	✓
General	Financial Incentives	✓	✓	✓	✓
	Utility Direct Investments in DERs	✓	✓	✓	✓
	Program Administration	✓	✓	✓	✓
	Utility Performance Incentives**	✓	✓	✓	✓
	Credit and Collection	✓	NM	✓	✓
	Risk	✓	✓	✓	✓
	Reliability & Resilience	*NM*	*NM*	*NM*	✓
✓	Both applicable and material				
NM	Not material, i.e., not large enough to merit routine inclusion				

* Per EmPOWER IE, this impact is considered but assumed to be zero based on state policy interpretation.

Source: ***Table S-3 and Table 6*** *in Work Group Report: Maryland Unified Benefit-Cost Analysis Framework for Distributed Energy Resources, Case No. 9674. May 16, 2024. Blue font rows indicate recommended modifications.*

*** For Utility Performance Incentives, new information was provided during the Phase II process that updated or corrected characterization of EmPOWER's accounting for this impact.*

**** The BE column was not included in the Phase I report but is added here because of the shift in EmPOWER goals that are now based on GHG emission reductions rather than on only electricity and gas savings. This has resulted in increased emphasis on building electrification. For gas utilities, the BE impacts are identical as for EE.*

Non-Utility System Impacts

The UBCA Work Group recommends two changes to non-utility system impacts in the MD-UBCA Test, as shown in Table 7:

Other Fuel Market Price Effects: Conceptually, impacts of DER investments on fuel oil, propane, gasoline, diesel and other unregulated fuel costs should include the effect of DER-driven changes in Maryland demand on market prices Maryland consumers pay for such fuels. However, petroleum prices are largely a function of global demand. Thus, for the purposes of the MD-UBCA, the recommendation is to assume that price effects are "not material" because small changes in consumption just in the state of Maryland are not expected to have a measurable effect on global prices.

Societal energy security: Further consideration by the Consultant Team led to the conclusion that Energy Security is already embedded in other MD-UBCA Test impacts, including utility system risk, reliability, and resilience.[18] As such, the UBCA Work Group recommends that Energy Security not be listed as a separate line item in the MD-UBCA Test.

[18] Energy Security impacts generally are captured through increased reliability and resilience of the grid (including physical and cybersecurity attacks), and reductions in risks to the utility system and customers (related to fuel prices, and energy independence). Further, certain energy security-related impacts may be captured in economic development analyses, which, as the Phase II process recognizes, are conducted separately from BCAs.

Table 7. Non-Utility System Impacts – MD-UBCA Test vs Current Maryland Practice

Impact	Maryland UBCA Test						EmPOWER BCA	PC44-EV BCA
	EE	DR	DG	DS	EV	BE		
Other Fuels								
Fuel and O&M	✓	✓	✓	NA	✓	✓	✓	✓
Delivery Costs (incl. other fuel T&D)	✓	✓	✓	NA	✓	✓	✓	Embedded
Environmental Compliance	✓	✓	✓	NA	✓	✓	Embedded	Embedded
Market Price Effects	*NM*	*NM*	*NM*	*NM*	*NM*	*NM*	✓	no
Other Utility System Impacts (if gas DER)	✓	✓	✓	NA	✓	✓	✓	no
Other Utility System Impacts (if electric DER)	✓	✓	✓	NA	✓	✓	✓	no
Host Customer Impacts								
DER Measure Costs	✓	✓	✓	✓	✓	✓	✓	✓
Transaction Costs	✓	✓	✓	✓	✓	✓	no	no
Interconnection Fees	NA	NA	✓	NA	NA	NA	N/A	N/A
Risk	✓	NA	✓	✓	✓	✓	% Adder*	no
Reliability[19]	NA						no	no
Resilience	✓	NA	✓	✓	✓	NA	% Adder*	no
Tax Incentive	✓	NA	✓	✓	✓	✓	✓	✓
Non-Energy Impacts (Non-Low-Income)	✓	NA	✓	✓	✓	✓	Partially**	Partially**
Non-Energy Impacts (Low-Income)	✓	NA	✓	✓	✓	✓	Partially**	Partially**
Societal Impacts								
Greenhouse Gas Emissions	✓	NM*	✓	NM*	✓	✓	✓	✓
Other Environmental Impacts	✓	✓	✓	NM*	✓	✓	✓	Embedded
Public Health	✓	✓	✓	NM*	✓	✓	Embedded	✓
~~Energy Security~~	Embedded in Utility System Risk, Economic Dev Impacts						% Adder*	no
Resilience	NA	NA	✓	✓	NA	NA	no	no

✓	Both applicable and material
NA	Not applicable to the given DER
NM	Not material, i.e., not large enough to merit routine inclusion
NM*	Not material in typical applications today but could be material in the future as the grid evolves

*Source: **Table S-4** for Other Fuels and Societal Impacts, **Table 15** for Host Customer Impacts, **Table 13** for all Current Maryland Practices (except "Other Utility System Impacts," which was inadvertently excluded from Table 13 in Phase I),[20] in Work Group Report: Maryland Unified Benefit-Cost Analysis Framework for Distributed Energy Resources, Case No. 9674. May 16, 2024. Blue font rows indicate recommended modifications.*

*According to IEs, EmPOWER EAG accounts for Risk via a 10% energy adder, though the 10% adder is considered to be a 'catch-all' for all unknown/unmonetized benefits, and thus, could be viewed to account for Risk, Reliability, Resilience, and Energy Security.

**EmPOWER BCA accounts for NEIs related to Comfort, O&M, Water Savings and Health & Safety. PC44-EV accounts for only host customer O&M.

[19] For clarity on distinction between host customer reliability and host customer resilience, see 2026 NSPM, Chapter 6 (Sections 6.3.5, pp. 6-10 to 6-13, and 6.8, p. 6-31).

[20] Note that water costs were included in the Phase I report Table 13 inadvertently; they are a subset of Host Customer Non-Energy Impacts, as shown in Table 8 of this Phase II report.

Additional detail on Host Customer non-energy related impacts in the MD-UBCA Test is provided in Table 8. A comparison of these impacts specific to the EmPOWER and PC44-EV current BCA practices was not specifically reviewed with the TMS or UBCA Work Group.

Table 8. Host Customer Impacts Non-Energy Impacts – MD-UBCA Test Additional Details

Impact	EE	DR	DG	DS	EV	BE
Non-Energy Impacts						
Asset Value	✓	NA	✓	✓	NA	✓
Water cost impacts	✓	NA	NA	NA	NA	NA
O&M costs	✓	NA	✓	✓	✓	✓
Productivity	✓	NA	NA	NA	NA	NA
Economic well-being	✓	NM	✓	✓	✓	✓
Comfort	✓	NA	NA	NA	NA	✓
Amenity	✓	NM	NA	NA	✓	✓
Health & Safety	✓	NA	NA	NA	NA	✓
Empowerment	✓	NA	✓	✓	✓	✓
Pride	✓	NM	✓	NM	✓	✓
✓	Impacts that are both applicable and material					
NA	Impacts that are not applicable to a given DER					
NM	Impacts that are "not material" or large enough to merit routine inclusion					

*Source: **Table 15** in Work Group Report: Maryland Unified Benefit-Cost Analysis Framework for Distributed Energy Resources, Case No. 9674. May 16, 2024. Blue font rows indicate recommended modifications.*

3.4. CONSULTATION WITH OTHER MARYLAND WORK GROUPS

Per the Commission's Order No. 91424, the UBCA Work Group and Consultant Team were directed to coordinate with the Commission's other existing work groups (Other WGs) where cost-effectiveness testing has been previously developed. These included the EmPOWER EAG, the MESP WG, the PC44-EV WG, and the ESP WG (formerly "Distribution" System Planning, or DSP, WG).

The Consultant team presented to each of the Other WGs at their scheduled meetings in August and September 2025. These presentations reviewed the Phase II scope, the relevance of the UBCA effort to each work group, and the current BCA practices used by the Other WGs (where relevant).[21] Subsequent to those meetings, the Consultant Team communicated with Other WG Leaders to understand regulatory and filing timelines related to DER BCAs and how those timelines should inform implementation of recommendations in this report.

[21] The Consultant Team presented to the PC44-EV Work Group on August 2, 2025, the EmPOWER EAG on August 20, 2025, the MESP Work Group on August 28, and the DSP Work Group on September 4. The Consultant Team also attended an MESP Work Group meeting on March 12, 2026.

In the case of the MESP WG specifically, the Consultant team also participated in a March 12, 2026 meeting, to better understand ongoing development of the MESP's Grid Services Tariff and Incentives program design study.

Chapter 5 describes how the recommendations in this report apply to Other WG scopes.

3.5. METHODS IMPLEMENTATION SCHEDULE AND PROCESS

During the TMS meetings, in particular Meeting 12, the Consultant Team presented a proposed schedule for adoption of the recommended methods – whether immediate, medium term, or long-term – and solicited feedback from the TMS. The recommended implementation timelines, reflecting this input, are described in Chapter 4.

Additionally, Chapter 6 discusses considerations for a statewide process to implement, and as necessary review and update, recommended methods over time.

3.6. METHODS REPORT DEVELOPMENT

This report reflects extensive feedback from TMS members over a nine-month period via (a) verbal comments during TMS meetings, (b) written feedback on preliminary and final methods recommendations through non-binding polls/surveys, and (c) one-on-one phone calls between the Consultant Team and TMS members to clarify concerns and talk through members' perspectives.

Through this process, the TMS reached consensus on many of the methods presented in Chapter 4. Chapter 4 also identifies areas of non-consensus or partial consensus and explains the reasons for those positions.

Following the final TMS meeting in late March 2026, the Consultant Team prepared a draft version of this Part 1 Methods Report for UBCA Work Group Leader review, followed by a two-week review period for the TMS, the broader UBCA Work Group, and Other WG leads and members. Written feedback on the draft report was provided by the EmPOWER IE, JMEU, MEA, OPC, WGL, Stack Energy Consulting, and Weavegrid.[22]

The Consultant Team presented the recommendations in this report and key feedback from commenters to the full UBCA Work Group on June 2, 2026 to gather additional comments. Members of Other WGs were also invited to attend this meeting.

Following this presentation and several direct meetings with some individual UBCA Work Group members to clarify certain comments, the Consultant Team prepared a final draft, made available for a one-week review period to the UBCA Work Group and Other WGs to ensure stakeholder positions were appropriately captured. After incorporating necessary changes, the Consultant Team provided this final report to the UBCA Work Group Leader for submission to the Commission.

[22] Stack Energy Consulting and Weavegrid were not part of the UBCA Work Group, but rather are members of Other WGs and provided comment on this UBCA Part 1 Methods Report.

4. MARYLAND UBCA TEST METHOD RECOMMENDATIONS

4.1. INTRODUCTION

This chapter presents the methods recommended for estimating all impacts in the MD-UBCA Test,[23] including all electric utility system, gas utility system, other fuel, host customer, and societal impacts. The recommendations herein were developed in consultation with the TMS as described in Chapter 3.2 and further informed by additional stakeholders in the UBCA Work Group and Other WGs who provided comment on draft versions of this report.

Where there is consensus, the UBCA Work Group recommends adoption of the methods described in this chapter. The UBCA Work Group further recommends that consensus "immediate" methods – and interim methods where needed – be implemented going forward for all BCAs being conducted for DER investment, subject to Commission discretion and as consistent with the schedules laid out in Chapter 5. For methods with partial agreement or non-consensus, the Commission may wish to (a) direct use of the Consultant Team's recommended method, (b) direct use of a different method, based on stakeholder positions, or (c) request additional information and/or proposals via written comments from stakeholders.

The recommended methods primarily focus on approaches to estimating average impacts for *system-wide* deployment of DERs. For DER investments that are designed to address *location-specific* needs – such as non-wires or non-pipe solutions designed to avoid or defer specific capital investments – certain impacts will need to be estimated on a project-specific (custom) basis (see Subsections 4.2.3, 4.2.4 and 4.3.3 for further discussion). However, even when addressing location-specific needs, several types of impacts remain appropriate to calculate on a system-wide basis. Projects-specific and system-wide impacts would then need to be added together to a complete BCA. For example, a geographically-targeted storage initiative designed to defer a substation upgrade would be associated with project-specific avoided distribution capacity costs that would need to be added to system-wide average avoided generation capacity costs, system-wide avoided energy costs, system-wide average avoided GHG emissions, etc.

Tables 9, 10 and 11 below summarize the recommended methods for each impact, with qualitative ratings for:

- Relative importance of the impact to DER cost-effectiveness determinations
- Level of cost and effort required to apply the recommended method, and
- Expected timeline by which the recommended method could be universally applied to DER BCAs in the state.

[23] All impacts in the MD-UBCA Test are discussed in Chapter 4 except for those which have been concluded by the UBCA WG to be embedded in other impacts and therefore proposed for removal as discrete impacts (see Section 3.3).

For impacts for which the recommended method may not be immediately actionable, the tables provide recommendations for interim methods. The Consultant Team recommends that interim methods be used only when it is infeasible to apply the recommended method within a regulatory deadline – i.e., it is always preferable to use the recommended method.

In reviewing the summary tables and supporting discussion of each impact in the rest of this chapter, it is important to consider the following:

- **UBCA Recommended Methods:** Per guidance from the UBCA Work Group Leader, the recommended methods are designed to collectively provide the best estimate of a DER's future benefits and costs, balancing trade-offs between methodological accuracy, implementation cost, and relative magnitude of each impact in a DER BCA. For some impact categories, the "best estimate" approach may be limited due to statutory requirements for the EmPOWER programs. Specifically, the EmPOWER EAG interprets statute[24] as functionally requiring avoided energy and capacity costs and associated emission impacts of the EmPOWER programs to be calculated based on the Maryland Department of Environment's (MDE's) forecast of how the state's energy production and consumption will achieve its decarbonization goals, regardless of that forecast's ultimate likelihood or accuracy. If EmPOWER continues to use the MDE forecast for EE, adoption of the methods recommended in this report for other DERs will result in some differences between approaches used to calculate BCAs for EE versus other DER types. However, in the Consultant Team's view, using methods that provide the "best estimates" of future DER values with significant but less than complete alignment on methods across DER types is preferable to ensuring alignment with less accurate estimates of the future.
- **Relative Importance when Assessing DER Cost-Effectiveness:** Tables 5 – 8 above identify each impact as applicable, not applicable, or not material for each DER type. In cases where an impact is applicable, its relative importance is characterized in Tables 9 – 11 as High (H), Medium (M) or Low (L). These ratings are subjective, based on the Consultant Team's and TMS members' experience. For most applications of most DERs, a few key impacts drive most of the calculated benefits and costs, as reflected in the number of impacts characterized as having "High" importance in the tables below. Impacts rated as "Medium" are those that can have a significant impact on cost-effectiveness but are typically not among the few key largest impacts. Impacts rated as "Low" will only rarely make a difference between a DER passing or failing the MD-UBCA Test (i.e., only in cases where the DER is close to the margin once all other impacts are valued), but can be important when considered in combination with other "Low" rated impacts.
- **Cost / Effort Required to Use Recommended Method:** Each recommended method is assigned a qualitative cost/level of effort rating – high ($$$), medium ($$) or low ($). This assessment is based on the required type of data collection, how readily available the data are likely to be, and the complexity associated with the analyses.

[24] Maryland Public Utilities Article § 7–223(b)(2) states that "when establishing greenhouse gas emission reductions targets" for efficiency programs, "the Commission shall measure the greenhouse gas emissions from electricity and gas, and the intensities of those emissions, using current data and projections from the Department of the Environment". In order to be consistent with such assumptions about greenhouse gas impacts, avoided electric energy and capacity costs are also being estimated relative to MDE forecasts.

- **Implementation Timeline for Recommended Method:** This is also a qualitative assessment. Impacts for which the recommended method could be applied relatively quickly with relatively modest effort were categorized as "immediate," meaning they can feasibly be incorporated into any DER BCA conducted after Commission approval (should the Commission approve). "Medium-term" methods require gathering of data not readily available and/or complex analysis and should be implementable within 6-12 months. Lastly, the Power System Modeling approach recommended for developing estimates of electric energy, electric capacity, GHG and other environmental impacts was categorized as "long-term." This method is expected to take 2+ years to implement, both because of the assumed reliance on the new Strategic Energy Planning Office ("SEPO") to lead the modeling effort (which will take the state time to stand up) and because Power System Modeling typically takes 9+ months when done with significant stakeholder input on assumptions and draft results.
- **Interim Method (for methods that cannot be implemented immediately):** These recommendations are "back-stops" for impacts for which the ultimate method may not be immediately actionable (i.e., the implementation timeline is characterized as medium- or long-term). As discussed above, if utilities or other parties can implement a recommended method sooner than anticipated, the Consultant Team recommends that they do so rather than rely on an interim method. For example, if a utility can use the primary method to develop a system-wide avoided electric distribution capacity cost for inclusion in a late 2026 EV initiative, it should be able to do so even if the interim method was used to file EmPOWER plans just months before.

The rest of the chapter provides the following for each impact:

- a *definition* of the impact;
- the *recommended method* for estimating its economic value;
- *key issues* considered in developing the recommended method, as discussed with TMS members, and in some cases with full UBCA Work Group members (see the Appendices for more detailed stakeholder feedback);
- a recommendation regarding both the *timeline for adoption* of the recommended method and, as applicable, an alternative *interim method*; and
- a summary of the *extent of agreement* within the TMS – and ultimately the UBCA Work Group stakeholders based on draft report comments – regarding the recommended method, timeline and interim method. Individual stakeholders' positions are specified for each proposed method. If a UBCA stakeholder is not explicitly called out as agreeing or disagreeing, this stakeholder did not provide a specific comment on the given method.[25] Stakeholders have agreed that UBCA Work Group consensus in this report is considered to have been reached if there is explicit agreement from stakeholders who provided comment on a specific impact method, and there is no disagreement from any stakeholder.

[25] The following Subsections provide detailed positions on each recommendation; high-level stakeholder positions are as follows: (1) Staff supports the positions of the EmPOWER EAG IE on the proposed UBCA methods herein. (2) Potomac Edison and SMECO abstain on all recommendations made in this report. (3) Columbia Gas is aligned with all consensus recommendations specified in this report.

Table 9. Summary of Recommendations for Electric Utility System Impacts

Impact Type	UBCA Recommended Method	Relative Importance when Assessing DER Cost-Effectiveness						Cost / Effort Required by Recommended Method	Implementation Timeline for Recommended Method	Interim Method (for those that cannot be implemented immediately)	Report Section
		EE	DR	DG	DS	EV	BE				
Generation Capacity	Power System Modeling (PSM)	**High**						$$$	Long-Term	Either (A) EmPOWER Assumptions; or (B) Values Derived from NLR Cambium.	4.2.1
Energy Generation	Power System Modeling (PSM)	**H**	L	**H**	L	**H**	**H**				
Env. / RPS Compliance	Embedded in energy/capacity costs	Embedded above									
Market Price Effects (energy & capacity)	Analysis of price/demand relationship using either: (A) recent market price data; or (B) PSM outputs	**H**	L	**H**	L	**H**	**H**	$$	**Energy**: Immediate **Capacity**: Medium term	**Capacity**: assume zero	4.2.2
Transmission Capacity	Ratio of Cost to Load Growth (using PJM RTEP data) for average system impacts; or project-specific values for non-wires solutions	Medium						$$	**System-wide:** Medium Term **NWS:** Immediate	EmPOWER Assumptions for system-wide impacts	4.2.3
Distribution Capacity	Ratio of Cost to Load Growth (using utility Distr. data) for system-wide and targeted, but not site-specific DER initiatives; or project-specific values for non-wires solution (NWS)	**High**						$$ / $$$	**System-wide and Targeted:** Medium Term **NWS:** Immediate	EmPOWER Assumptions for system-wide and targeted impacts	4.2.4
Distribution O&M	Recommend treating as "not material", so no recommended methodology.	NM						NA	NA	NA	4.2.5
Transmission & Distribution System Losses	(A) statistical analysis of marginal relationship between losses and load; ***or*** (B) default multipliers of readily available average annual energy loss rates	Medium/Low						$	Immediate	NA	4.2.6
Ancillary Services	Historic price approach - but applied only for DERs assumed to be bid into PJM; otherwise assumed to be "not material"	NM	L	L	M	NM	NM	$	Immediate	NA	4.2.7
Risk	Adder = 10% for all electric system benefits for all DERs, except DR (5%). *Values are negative for electrification*	Medium / Low						$	Immediate	NA	4.2.8
Reliability	Application of LBNL ICE calculator	Medium / Low						$$ / $	Immediate	NA	4.2.9
Resilience	None required. Optional analysis of customer "stated preferences" for DERs expected to produce large benefits beyond reliability.	Low						$$	Immediate	NA	4.2.10
Credit & Collection Costs	2% of forecast energy bill savings from major DERs delivered to low- income customers	L	NM	L	NM	L	L	$	Immediate	NA	4.2.11
Utility $ to Promote DERs	Costs as forecast or incurred for incentives, direct investment, program admin, etc.	**High**						$	Immediate	NA	4.2.12

Table 10: Summary of Recommendations for Gas Utility System Impacts

<table>
<tr><th rowspan="2">Impact Type</th><th rowspan="2">UBCA Recommended Method</th><th colspan="3">Relative Importance when Assessing DER Cost-Effectiveness</th><th rowspan="2">Cost / Effort Required by Recommended Method</th><th rowspan="2">Implementation Timeline for Recommended Method</th><th rowspan="2">Interim Methodology (for methods that cannot be implemented immediately)</th><th rowspan="2">Report Section</th></tr>
<tr><th>EE</th><th>DR</th><th>BE</th></tr>
<tr><td>Energy</td><td>Henry Hub + Basis, with basis values derived from 3 years of historic differences between Henry Hub costs and delivered cost to distribution system</td><td colspan="3" rowspan="3">High</td><td rowspan="3">$$ / $</td><td rowspan="3">Immediate</td><td rowspan="3">NA</td><td rowspan="3">4.3.1</td></tr>
<tr><td>Transmission Pipeline Capacity</td><td>Embedded in approach to Energy</td></tr>
<tr><td>Env. Compliance</td><td>Embedded in Energy costs</td></tr>
<tr><td>Market Price Effects</td><td>Recommend treating as "not material", so no recommended methodology.</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.2</td></tr>
<tr><td>Distribution Local Delivery Capacity</td><td>Ratio of Cost to Load Growth (using utility Distribution data). Analysis only of areas forecast to experience growth, with results then weighted with zero value to rest of system for average system-wide impact; project-specific values for non-pipe solution (NPS).</td><td colspan="3">Low</td><td>$$ / $$$</td><td>System-Wide: Medium Term NPS: Immediate</td><td>Assume zero impact for system-wide</td><td>4.3.3</td></tr>
<tr><td>T&D (‘Pipeline’ & ‘Local Delivery Line’) Losses</td><td>Recommend treating as "not material", so no recommended methodology.</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.4</td></tr>
<tr><td>Risk</td><td>Adder = 10% for gas system benefits for all efficiency and electrification; 5% for DR.</td><td colspan="3">Medium / Low</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.5</td></tr>
<tr><td>Reliability and Resilience</td><td>Recommend treating as “not material”, so no recommended methodology</td><td colspan="3">NM</td><td>NA</td><td>NA</td><td>NA</td><td>4.3.6</td></tr>
<tr><td>Credit & Collection Costs</td><td>Adder equal to 2% of forecast energy bill savings from major DERs delivered to low-income customers</td><td>L</td><td>NM</td><td>L</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.7</td></tr>
<tr><td>Utility $ to Promote DERs</td><td>Costs as forecast or incurred for incentives, direct investment, program admin, utility performance incentives, etc.</td><td colspan="3">High</td><td>$</td><td>Immediate</td><td>NA</td><td>4.3.8</td></tr>
</table>

Table 11: Summary of Recommendations for Host Customer, Other Fuel, GHG and Other Environmental Impacts

<table>
<tr><th rowspan="2">Impact Type</th><th rowspan="2">UBCA Recommended Method</th><th colspan="6">Relative Importance when Assessing DER Cost-Effectiveness</th><th rowspan="2">Cost / Effort Required by Recommended Method</th><th rowspan="2">Implementation Timeline for Recommended Method</th><th rowspan="2">Interim Methodology (for methods that cannot be implemented immediately)</th><th rowspan="2">Report Section</th></tr>
<tr><th>EE</th><th>DR</th><th>DG</th><th>DS</th><th>EV</th><th>BE</th></tr>
<tr><td rowspan="2">Host Customer Impacts</td><td rowspan="2">Mix of research + proxy adders. 3-step process recommended to:
(A) identify material NEIs for each DER;
(B) monetize (i) customer measure costs; (ii) tax credits; (iii) O&M costs; (iv) water costs;
(C) adopt proxy adders and/or specific values based on research/analysis</td><td colspan="6">Costs:
High</td><td rowspan="2">$$ / $</td><td rowspan="2">(A) Immediate
(B) Immediate
(C) Medium-Term</td><td rowspan="2">Assume zero impact for (C) for anything other than customer measure costs, tax credits, O&M cost and water costs.</td><td rowspan="2">4.5</td></tr>
<tr><td>Benefits:
M/L</td><td>L</td><td>L</td><td>L</td><td>M/L</td><td>M/L</td></tr>
<tr><td>Other Fuels</td><td>Forecasts of other fuel prices:
(A) EIA reference for current prices for building fuels (propane/fuel oil) and transportation fuels (gasoline/diesel);
(B) EIA AEO regional forecast to escalate prices into future years</td><td>M</td><td>L</td><td>L</td><td>NA</td><td>H</td><td>H</td><td>$</td><td>Immediate</td><td>NA</td><td>4.4</td></tr>
<tr><td>GHG Emissions</td><td>Two key parts:
(A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels;
(B) Social Cost Carbon to translate emission impacts to $</td><td>H</td><td>NM</td><td>H</td><td>NM</td><td>H</td><td>H</td><td>$$$</td><td>Electric:
(A) Long-Term
(B) Immediate
Gas/Other Fuels:
(A) Immediate
(B) Immediate</td><td>For Electric (Part A): Either EmPOWER assumptions
or
Values from NLR Cambium for Electric</td><td>4.6.1</td></tr>
<tr><td>Other Environmental / Public Health (Criteria Pollutants)</td><td>Two key parts:
(A) estimating emission impacts through (i) Power System Modeling for electric grid; and (ii) use of EPA emission factors for fossil fuels;
(B) EPA COBRA to translate emission impacts to $</td><td>M</td><td>L</td><td>M</td><td>NM</td><td>H</td><td>M</td><td>$$$</td><td>Electric:
(A) Long-Term
(B) Immediate
Gas/Other Fuels:
(A) Immediate;
(B) Immediate</td><td>For Electric (Part A): Either EmPOWER assumptions
or
Extrapolation from GHG values from NLR Cambium for Electric</td><td>4.6.2</td></tr>
<tr><td>Societal Resilience</td><td>Defer to future - recommend separate workgroup process to identify appropriate key metrics and methodological recommendation</td><td>NA</td><td>NA</td><td colspan="2">Med/Low</td><td>NA</td><td>NA</td><td>$$</td><td>Medium to Long-Term</td><td>Qualitative Assessment only</td><td>4.6.3</td></tr>
</table>

4.2. ELECTRIC UTILITY SYSTEM IMPACTS

4.2.1. Electric Generation Capacity and Energy Costs

Definition

1. **Energy:** Variable costs (fuel, operating & maintenance) associated with the production or procurement of energy from generation resources. DERs affect these costs by either (a) reducing the amount of generation or procurement required to meet load (a benefit), or (b) increasing the amount required (a cost).
2. **Capacity:** Costs associated with generation capacity required to meet peak load plus any associated planning reserve margin. Typically includes cost for the construction or procurement of generation capacity.

Recommended Method

Future marginal energy and capacity costs should be estimated using power systems modeling (PSM) that compares scenarios with and without DER projects and programs. Modeling should include both capacity expansion and production cost functions. This report makes the assumption that SEPO will perform any required modeling.[26] When SEPO becomes operational, in the case that the office ultimately does not perform the modeling this report anticipates, the Commission may wish to explore alternative approaches, including alternative entities to be responsible for PSM. Specific steps for PSM are as follows:

1. **Determine key inputs for reference cases:** Work with stakeholders, including state agencies, Commission staff, utilities, and others to collaboratively determine key inputs such as load forecasts, generating facilities, fuel prices, and operational characteristics, for the following reference case modeling scenarios:
    a. **Standard Reference Case:** All standard input assumptions based on current market conditions and policies.
    b. **MDE Case:** All standard input assumptions based on the Maryland Department of Environment (MDE) load forecast and related assumptions about market conditions and policies.
2. **Determine energy efficiency inputs:** Work with stakeholder group to create a portfolio of programs (EE, DG, and BE.)
    a. **Counterfactual Standard Reference:** All standard input assumptions with the program portfolio removed.
    b. **Counterfactual MDE:** All MDE input assumptions with the program portfolio removed.
3. **Develop inputs for any other counterfactual scenarios**: Work with stakeholder group to identify additional scenarios needed to aid in evaluating cost-effectiveness of other DERs (i.e., EV, DS, DR, DG). Such additional scenarios could remove assumed levels of DER deployment within the reference case to provide insight into the cost-

[26] SEPO and Commission interactions per statute are laid out in SB 909 (2025), https://mgaleg.maryland.gov/2026RS/bills/sb/sb0909F.pdf

effectiveness of already planned DER investment. Alternatively, they could vary assumed deployment level of any type of DER to provide insight into the sensitivity of costs to different levels of DER investment.

4. **Estimate marginal cost & emissions effects:** Estimate marginal future energy cost ($/MWh), capacity cost ($/MW) and marginal emissions impacts by comparing reference and counterfactual cases:
    a. **Marginal costs =** (difference in total costs) ÷ (difference in demand). This value represents the marginal cost associated with the program portfolio being assessed in the counterfactual case.
    b. **Marginal emissions effects =** (difference in total emissions) ÷ (difference in MWh demand). This value represents the marginal emissions associated with the program portfolio being assessed in the counterfactual case. See Subsection 4.6.1.
5. **Assess any direct cost effects:** Use the reference case hourly energy and seasonal capacity market price forecasts to directly assess cost effects from specific DERs, particularly those that shift load (e.g., DR and DS). This is done by applying those price forecasts directly to an incremental hourly load forecast for those projects.

Outputs:

- For direct use to represent cost effects of modeled projects or programs that change the magnitude of energy sales (e.g., EE, DG like distributed solar, BE, and EV):
    - Hourly marginal wholesale energy cost by utility ($/MWh);
    - Summer and winter marginal capacity cost by region ($/MW);
    - Hourly marginal CO_2 and criteria pollutant emissions (tons or lbs/MWh)
- For use with anticipated hourly load shapes for DERs that shift loads (DR, DS):
    - Hourly wholesale energy cost by utility ($/MWh);
    - Summer and winter capacity cost by region ($/MW);
    - Hourly CO_2 and criteria pollutant emissions (tons or lbs/MWh)
- For use to assess emissions cost effects:
    - Hourly marginal CO_2 and criteria pollutant emissions (tons or lbs/MWh)
    - While the model will produce marginal emissions rates, it will not translate those into cost effects. The method for monetizing emissions impacts is discussed in Section 4.6 below.

A PSM approach can provide a standard set of values, as illustrated in an example in Table 12.

Table 12: Sample Power Systems Modeling Outputs (levelized costs)[27]

Marginal Effect	Unit	Reference	MDE
Costs			
Energy	2028 $/MWh	$30	$32
RPS Compliance	2028 $/MWh	$15	$17
Capacity	2028 $/MW-year	$20	$22
Emissions			
CO2	Metric Tons per MWh	0.3	0.2
NOx	Pounds per MWh	0.025	0.022
SOx	Pounds per MWh	0.021	0.010

Substantial Market Change Approach

If, while preparing for recurring filings, market price forecasts change substantially from the modeled reference case price forecast and a DER-related filing must be made before new PSM results that reflect such changes will be available, it is recommended that utilities be permitted to use an alternative market price forecast as long as (1) actual PJM prices differ sufficiently from the PSM reference case forecast; (2) the alternative forecast is publicly available; and (3) the alternative forecast is from a reputable source. If the annual energy market price for the relevant PJM hub should differ from the PSM reference case forecast by at least 25% (above or below) the previous year, utilities may use another market price forecast that reflects such changes. PJM capacity market prices are expected to remain high in the near future, as reflected in the 2026/2027 and 2027/2028 Base Residual Auctions (BRAs).[28, 29] Given the extension of the PJM capacity market price floor and collar,[30] there is a maximum level these prices may reach. If the unconstrained near-term PJM forward auction results (i.e., what prices would be without a price floor or cap) differ from the PSM modeled reference case capacity price forecast, the utilities may use those results and escalate at the rate determined by the PSM model. It is not recommended that utilities be permitted to use a different long-term forecast for capacity prices.

Key Issues

The outlined PSM approach involves use of industry-standard capacity expansion and production cost models to generate a detailed set of cost effects, specific to each Maryland utility and at an hourly level.[31] Central to this recommendation is the "Counterfactual Scenario" – long used by the New England states in their Avoided Energy Supply Costs

[27] In this sample summary table, costs are levelized over an appropriately long time period (e.g., 15 years). However, PSM should also produce separate annual cost outputs for each year analyzed (e.g., for each of the next 25 years).
[28] 2026/2027 Base Residual Auction Report, PJM, July 22, 2025; https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf
[29] 2027/2028 Base Residual Auction Report, PJM, December 17, 2025; https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdfo
[30] FERC Approves Capacity Auction Price Collar to Next Two Capacity Auctions, PJM Inside Lines, April 30, 2026; https://insidelines.pjm.com/ferc-approves-capacity-auction-price-collar-to-next-two-capacity-auctions/
[31] If determined to be important and/or valuable enough, PSM scenarios could also be developed at sub-utility levels (i.e., for different zones or nodes within a utility service territory).

(AESC) process.[32] As compared to a Reference Case, which includes all forecasted DER programs, the counterfactual scenario under this approach represents a future in which a certain program or programs are not implemented. The marginal cost effect of those programs is thus determined by finding the difference between the Reference and Counterfactual scenarios and dividing by the demand for each. The PSM counterfactual approach is beneficial especially for EE, which is often embedded in standard market price forecasts. A counterfactual explicitly removing EE enables a comparison to a baseline.

Two reference cases, one reflecting expected utility load forecasts and one aligned with MDE forecasting assumptions, ensure that modeling captures both standard operations given current market conditions and a policy-driven potential future. These reference cases inherently include renewable portfolio standard (RPS) compliance costs as well as the costs associated with any other state or federal policies.

For DERs that primarily shift loads (such as DR and storage) and are not included in a counterfactual scenario, the outputs from the reference case scenarios can be directly applied.

Methods Considered

Th Consultant Team presented three broad methodological approaches for consideration: the PSM approach (recommended above), the blended market price forecast approach, and the hybrid forecast approach. Blended market price forecasting and hybrid forecasting are currently used in Maryland and are discussed below.

Current Energy Forecasting Practices

Maryland utilities currently use a blended market price forecast in most cases. For near-term energy cost effects, utilities use near-term PJM energy futures by zone (e.g., Pepco and DPL) accessed via S&P Capital IQ. These futures are blended with long-term price forecasts from data vendors or public modeling sources, such as NLR (National Laboratory of the Rockies, formerly the National Renewable Energy Laboratory) Cambium. The utility may make assumptions related to scale and geography, or may use generic 8760 generation load shapes while combining these two forecasts. Ultimately, these forecast prices are applied to program- or project-specific load profiles to determine an estimated cost effect.

The ’hybrid market approach’ currently employed by the EmPOWER IE strives to determine higher granularity energy effect values in line with specific Maryland policy. The EmPOWER IE uses a spreadsheet model to approximate a market price forecast using MDE current and planned policies for load forecast and generation mix. For each generation type, EIA or NYMEX fuel and operating costs and heat rate assumptions are applied to generic resource blocks, resulting in a state-level system-wide annual cost. To derive utility-specific costs, ancillary, congestion, and other costs are layered on. The marginal unit is identified and the $/kWh value for that unit is used as the energy cost effect value.

[32] https://www.synapse-energy.com/aesc-2024-materials

Current Capacity Forecasting Practices

In the near-term, both the utilities and EmPOWER IE use PJM BRA results for capacity prices. In the long-term, utilities blend long-term price forecasts from public sources, primarily NLR Cambium, similar to the process described for energy market prices above. The EmPOWER IE uses the PJM-calculated Net CONE (cost-of-new entry) for the anticipated marginal unit (typically a gas combustion turbine or battery storage system), as a proxy value for long-term capacity cost.

Elements Considered

When comparing the three identified methodological approaches (PSM versus blended market price or hybrid forecasting), the following elements were considered:

- **Standardization:** Market price and hybrid market approaches are not standard across utilities and/or may involve different assumptions than utilities use internally. The PSM approach can be applied in a standardized way across all Maryland utilities, and with input from those utilities and other stakeholders on driving assumptions.
- **Transparency and Collaboration:** The market price forecast approach relies on well-known and respected sources, but inputs and underlying assumptions are not easily determined and cannot be collaboratively shaped by Maryland parties. In contrast, the PSM approach enables collaborative and transparent input assumption development.
- **Timeline:** Stakeholders discussed in-depth the tradeoff between PSM's improved granularity and its longer implementation timeline. The first SEPO report to the Commission is required by September 1, 2028, with updates every three years thereafter.[33]
- **Cost:** Cost was a major topic of discussion in the working group. While market price forecast approaches are built into existing utility staffing and process, and the hybrid approach is included in the EmPOWER IE process, PSM may cost the state somewhat more overall relative to those approaches if funded by the utilities. Given the establishment of a state modeling office, these costs are assumed to be incorporated into that office's scope and budget. If, for any reason, PSM must be funded external to state government, the Consultant Team estimates an average cost of $20,000-$35,000 per year for each utility.[34] Cost-estimating can be more formally revisited should the approach to PSM become utility-funded in the future.
- **Consistency Across Values:** PSM produces internally consistent energy, capacity, and emissions outputs based on a single set of collaboratively developed assumptions. Depending on the source, market price forecast and hybrid approaches may provide aligned energy and emissions outputs, but not capacity. Further, market price forecasts are not developed using load forecasts specific to Maryland policy mandates

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[33] https://mgaleg.maryland.gov/2025RS/fnotes/bil_0007/hb1037.pdf

[34] This assumes PSM costs on the order of $300,000 to $500,000 (estimated based on a proprietary source) with modeling conducted every three years (i.e., $100,000 to $167,000 per year) with costs spread across five Maryland electric utilities (BG&E, PEPCO, Potomac Edison, Delmarva, and SMECO). This cost is also *not* necessarily incremental to what it currently costs utilities to develop estimates through their current blended market price forecasting approaches. Any such existing costs would need to be directly compared to the above estimates to obtain an incremental cost value. For those utilities not regularly performing BCAs, costs may be entirely incremental.

(e.g., MDE). As a result, market price forecast and hybrid approaches risk inconsistency across their forecast values.

- **Analytical Comparison and Granularity**
  - *Temporal Granularity:* Market price approaches typically convert available data to hourly values using generic 8760 load shapes; the hybrid approach uses actual historical load. Some market price forecasts are available for purchase at an hourly granularity but cannot be disseminated publicly. Standard PSM now provides outputs at 8760 temporal granularity.
  - *Geographic Granularity:* Market price forecasts are generally limited to large zonal areas (e.g., NLR Cambium's PJM East zone). Both the hybrid and PSM approaches are capable of producing utility-specific outputs.
  - *Accuracy:* PSM uses unique cost and operational values for each generating asset on the system. Some market price forecasts may also include this high level of system accuracy. However, the hybrid approach relies on generic resource assumptions which are sufficient but not as detailed as the other methods.

Timeline for Adoption & Interim Method

The expected timeline for implementation of these solutions will depend heavily on the timeline for executing SEPO-related legislation. Once the SEPO is established, this report assumes that their modeling would incorporate a counterfactual EE/DER scenario in its first round of effort.

Until PSM results are available, utilities and intervenors who participate in BCA proceedings before the PSC may use either: (1) EmPOWER values; or (2) NLR Cambium forecasts. The choice between these options may depend on: which is most accurate for a given DER type; historical practice for that DER (i.e., expediency); and/or a desire for consistency across DERs. Methods used in past DER filings may also continue to be used for those proceedings.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

The recommendation to use PSM is supported by OPC, the EmPOWER IE, and JMEU as the best tool for achieving granular and accurate forecasts with the ability to be vetted by multiple stakeholders. Some supporting parties expressed reservations (EmPOWER IE) or conditioned their support (JMEU). Support for this approach was predicated on the ability of all stakeholders to be actively engaged in the modeling process, including input and feedback on key assumptions. Expectations around cost and labor were heavily discussed at the beginning of the working group process, but concerns were largely assuaged following the passage of MD HB1037 establishing the SEPO. The Consultant Team would recommend PSM even if it had to be led and funded by utilities. However, support for PSM from the JMEU is conditioned on the establishment of the SEPO and the cost of the modeling being born by that office (due to concerns about cost to ratepayers). A verbatim presentation of the JMEU conditions for supporting PSM is provided in Appendix C (subsection A.2, pp. 6-7).

The JMEU also disagreed with the interim proposal to allow the use of either EmPOWER values or NLR Cambium forecasts until PSM can be undertaken. Instead, the JMEU proposed to require use of NLR Cambium values for all DERs other than EE because they are expected to be more accurate. The JMEU contends that the current range of options and flexible selection criteria are too broad to effectively serve the purpose of providing clear, actionable guidance for standardizing BCA inputs.

While the Consultant Team agrees that the NLR Cambium forecasts may be more accurate today, that could change prior to the availability of PSM outputs as MDE forecasts and/or NLR Cambium forecasts are updated. Further, for the interim period until PSM outputs are available, the Consultant Team suggests it is reasonable to consider tradeoffs between accuracy, expediency and the consistency across analyses of different DERs. Utilities and other stakeholders who prefer to use NLR Cambium forecasts for assessing a given DER, on the grounds that accuracy supersedes expediency and/or consistency, can make that case in individual DER proceedings.

4.2.2. *Market Price Effects – Energy and Capacity*

Definition

Market price effects are changes in wholesale market prices that result from a change in energy consumption. They are the manifestation of the fundamental “law of supply and demand” – i.e., when demand declines, prices go down (and vice versa). DERs can produce:

- **Energy price effects:** changes in hourly wholesale energy market clearing prices, and
- **Capacity price effects:** changes in capacity market clearing prices resulting from changes in peak demand.

These effects are distinct from direct changes in energy and capacity costs discussed above. Consider a hypothetical utility system with 100,000 MWh of energy consumption in a given hour of the year. If a DER reduces energy consumption by 1000 MWh in an hour with a market clearing price of $0.100/kWh, the directly avoided energy cost would be $100,000. The market price effect is the *additional effect* that reducing consumption has on the remaining 99,000 MWh of sales in that hour by potentially eliminating the need for the most expensive generator that would otherwise be dispatched that hour. If the most expensive generator required to operate to serve the remaining 99,000 MWh of load in that hour costs $0.099/kWh, that becomes the market clearing price for remaining 99,000 MWh of load. Thus, in addition to directly saving $0.100/kWh for 1000 MWh ($100,000), there is a savings of $0.001/kWh for the remaining 99,000 MWh of load ($99,000).

Recommended Method

The recommended approach to estimating market price effects is to analyze the relationship between demand and wholesale prices. This approach has the following steps:

1. Analyze the relationship between demand (kWh) and energy prices across all hours of the year, as well as the relationship between peak demand (kW) and capacity prices. This can be done in one of two ways:
    a. Statistical analysis (e.g., regression analysis) of historical market price data
    b. Analysis of PSM results
2. Multiply $/kWh and $/kW price shifts estimated in Step 1 by the total annual kWh sales and total peak demand forecasted to remain after DER deployment.
3. Adjust values down to account for the portion of sales over time that are hedged (i.e., the share of annual sales that have “locked” prices through contracts), as prices that

are already fixed through contracts will not experience market price effects. Note that a higher portion of electricity sales are hedged in the near-term (i.e., a year or two) and typically much less is hedged in the medium to longer term.

4. Estimate the rate at which price effects are expected to decay over time due to expected responses by generators, customer demand elasticity and other factors. Absent a Maryland or PJM-specific analysis, the New England AESC decay assumptions should be used. The most recent AESC study available at the time of the writing of this report (i.e., the 2024 AESC) had the following decay assumptions for the New England region as a whole, as shown in Table 13.[35]

Table 13. AESC Decay Assumptions

Years after DER Deployment	% Energy Price Effect Remaining	% of Capacity Price Effect Remaining
1	95%	100%
2	94%	83%
3	93%	67%
4	92%	50%
5	91%	33%
6	88%	17%
7	84%	0%
8	79%	0%
9	70%	0%
10	58%	0%
11	40%	0%
12	0%	0%

One caveat to the approach above is that estimates of market price effects should be bounded by any market price ceilings or floors. For example, if capacity prices are currently being capped by a price ceiling, it could be reasonable to assume zero capacity price effects on the premise that it is unlikely that the typically very modest (per kW) magnitude of price effects from DERs that reduce load will be sufficient to bring prices below the ceiling. However, that would only apply to the years for which capacity prices are forecast to be capped, which may be less than the full life of long-lived DERs.

Key Issues

The TMS discussed several different issues related to the recommended method for estimating market price effects:

[35] Synapse Energy Economics et al., Avoided Energy Supply Components in New England: 2024 Report, prepared for the AESC 2024 Study Group, Amended May 24, 2024 (https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc). See Table 104 on p. 240 for energy price effect decay rate for ISO-NE and Table 110 on p. 248 for capacity price effect decay rate. Note that a new AESC study is expected to complete in early 2027.

- **Historical Price Data versus PSM**. The EmPOWER IE suggests that only statistical analysis of historic market price data should be allowed – and that basing market price effects on outputs from PSM should not be allowed. The rationale for this position is that actual market data are more likely to provide defensible estimates of the price-demand relationship. The counter-argument is that there is value in aligning assumptions on market price effects with the analysis that will be used to estimate energy and capacity costs. While the Consultant Team currently has greater confidence in the statistical analysis option, it believes both positions have merit, so it continues to support deferring a decision on which approach to use until final decisions on the scoping of PSM have been made and PSM-based market price effect outputs can be assessed for reasonableness. However, once an option is selected, it should be applied to all DERs so that there is consistency in how they are analyzed.
- **Uncertainties about how PSM will be conducted**. Utilities raised the same questions about PSM here as are discussed above in Subsection 4.2.1.
- **Decay rate**. It is not clear how one might empirically assess the decay rate of price effects. Historically, EmPOWER has assumed that market price effects decay to zero over a four-year period. It is recommended that the New England AESC decay rates (i.e., reaching zero remaining price effect after 11 years for energy and after 6 years for capacity) be used as default assumptions because they are revisited and updated for each AESC study, and reflect the study authors' market expertise and assumptions. The decay factors they assume in the 2024 AESC report[36] are summarized as follows:
    - Owners of existing generating capacity would tend to allow generation assets to become less efficient and less reliable over time because of less attractive prices, leading to more outages and therefore higher prices (more expensive generation is required when lower cost generation cannot operate);
    - Expectations that consumers will gradually respond to lower prices by gradually increasing demand for energy over time, thereby raising prices back up; and
    - Reductions in demand for energy will mean reductions in low-energy-cost renewables being deployed in states with a binding RPS.

Note that at least one other analyses of market price effects has also estimated that energy price effects decay to zero over at least a decade. For example, a 2014 Illinois analysis assumed a 13-year decay period.[37] That said, as with other utility system cost estimates, there are mixed views and uncertainty associated with assumptions on this issue.

Timeline for Adoption and Interim Method

As discussed in Subsection 4.2.1, it will likely be several years before PSM can be done. However, market price effects can be estimated more quickly through statistical analysis of PJM market data. The EmPOWER IE team recently completed such an analysis for electric

[36] AESC 2024, pp. 239-240. https://www.synapse-energy.com/sites/default/files/AESC%202024.pdf

[37] For example, see Chernick, Paul (Resource Insight) and Chris Neme (Energy Futures Group), The Value of Demand Reduction Induced Price Effects (DRIPE), Regulatory Assistance Project webinar presenting results of 2014 Resource Insight analysis of DRIPE in Illinois, presented March 18, 2025 (https://www.raponline.org/wp-content/uploads/2023/09/efg-ri-dripewebinarslidedeck-2015-mar-18-revised.pdf).

energy.[38] That analysis was conducted assuming MDE estimates of future electricity sales in Maryland. The results could be recomputed for application to other DERs based on PJM sales forecasts (which for 2026 are about 13% higher than MDE estimates[39]). This would be a relatively simple adjustment, so the Consultant Team recommends that this method for estimating market price effects be applied immediately.

There has been no comparable analysis of capacity price effects. Such an analysis will take some time to conduct so the recommended method for capacity price effects should not be expected to be universally applied until up to a year after it is formally approved. However, it can be utilized sooner than if there is an ability to do so.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

EmPOWER IE, OPC, and JMEU all agree on the merits of the option of using statistical analysis of price and demand relationship. However, there is some disagreement over whether PSM should also be an allowed option for estimating the demand-price relationship. Specifically, the EmPOWER IE suggests that only statistical analysis of historic market price data should be allowed while the utilities appear to prefer relying on PSM (though JMEU indicated it would use the EmPOWER statistical analysis of historic price data if PSM was not available).

4.2.3. Electric Transmission Capacity Costs

Definition

Electric transmission capacity costs are the costs associated with delivering electricity from generators to electric utility distribution systems (and sometimes directly to very large individual customers). They are predominantly the capital costs incurred to ensure that the delivery capacity of transmission lines is sufficient to meet the peak demands of customers downstream of those lines.

There are two scenarios in which the potential value of avoiding or deferring electric transmission capacity costs should be considered in DER BCAs:

1. Non-wires solutions (NWS) in which EE, DR, DG, and/or storage are targeted to specific geographic areas to defer or avoid a specific transmission system investment; and
2. System-wide DER initiatives involving programs offered to all electric customers.

Recommended Method – NWS

For an NWS, the potential economic benefit should be estimated based on the specific investment being deferred or avoided.[40] The overarching approach should be to compute the difference between:

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[38] For a summary of the EmPOWER analysis, see: https://drive.google.com/drive/folders/1ToapaXd_jV9GqKnojBgyM6lxt0Y3HBsi.

[39] Per the EmPOWER analysis, the PJM forecast 2026 sales to Maryland customers is 67,928,100 MWh, which is 13% higher than the MDE forecast of 60,025,121 MWh which was used by EmPOWER to estimate energy price effects. See Demand Side Analytics, "Maryland Electric Energy Demand Reduction Induced Price Effects Study", July 15, 2025, slides 15 and 19.

[40] See Code of Maryland Regulations §20.50.15(G)(2), which discusses Locational Value Assessment.

A. the net present value (NPV) of the stream of revenue requirements associated with the capital investment in a scenario in which the NWS is not deployed; and
B. the NPV of the stream of revenue requirements associated with the capital investment for a period of time because of the NWS.

The value of deferring a capital investment is associated with the time value of money, which will be a function of the 2% real discount rate adopted by the Maryland Commission in the UBCA Phase 1 process.[41] The longer a capital investment is deferred, the greater the difference in NPVs and therefore the greater the economic value of the NWS. If an NWS is estimated to be sufficient to eliminate or indefinitely avoid the need for a capital investment entirely, the value of the avoided capital investment will simply be the NPV of the stream of revenue requirements associated with the capital investment under the no NWS scenario.

Recommended Method – System-Wide DER Initiatives

For system-wide DER initiatives (e.g., EE programs or DS incentives that are available to all of a utilities' customers rather than just those in specific, targeted geographic area), electric transmission system capacity cost impacts should be estimated using the Ratio of Cost to Load Growth method using the following steps:

1. Estimate future capital investments planned to address peak load growth in Maryland, based on the most recent PJM Regional Transmission Expansion Plan (RTEP) list of planned projects for Maryland. The RTEP lists all planned transmission projects, projected in-service dates, and costs by state. Projects for Maryland and the District of Columbia are presented together, though it is clear which are physically located in each jurisdiction. Analysis and judgment will be required to determine which projects are related to peak load growth.
2. Identify the portion of the transmission costs identified in Step 1 that are associated with summer peak load growth vs. winter peak load growth. To the extent that some projects are needed address both summer and winter peak demands, judgment will be needed to reasonably allocate projects costs to each season.
3. Estimate both summer and winter peak demand load growth for the period of time covered by the PJM RTEP.
4. Divide the estimated cost of future summer and winter load growth-related investments from Step 2 by the estimated summer and winter peak load growth from Step 3 to produce separate summer and winter costs per unit of peak load growth. Estimates should be expressed in terms of $/kW.
5. Annualize capital costs by multiplying the total cost per unit of peak load growth developed in Step 4 using a real (i.e., inflation adjusted) levelized carrying charge over the cost-weighted average life of the growth-related capital investments from Step 4.

Key Issues

A range of issues associated with the development of system-wide transmission costs are worth highlighting. They include:

[41] Real discount rates exclude the effects of inflation. If the streams of revenue requirements are expressed in nominal dollars (i.e., including forecast effects of inflation), then a higher nominal discount rate that includes forecast levels of inflation would be used instead.

- **Low peak load growth scenarios**. One question raised during discussion was whether the proposed approach to estimating annual average transmission cost impacts for system-wide DERs would be problematic if there was no load growth (i.e., dividing costs by zero) or very low peak load growth. In such circumstances, the approach can be modified to (A) address only areas experiencing peak load growth (i.e., dividing forecasts costs in such areas by growth in peak demand in such areas); and (B) computing a system-weighted average cost based on the portion of total peak demand associated with such growth areas and the portion associated with areas without peak demand load growth. This conceptual approach is discussed in more detail in the gas distribution cost section below.
- **Challenges with determining which planned PJM projects for Maryland are related to load growth**. While some electric transmission investments are clearly not related to load growth and some are clearly driven entirely (or almost entirely) by load growth, there are others for which addressing load growth is just one of several factors driving the investments. In such cases, judgement will be required when determining the capital cost to include in Step 1. It could be reasonable to assign a portion of the capital cost of such a project to load growth – again, based on expert judgment of the importance of load growth as a factor in project. Such determinations will likely require discussions with PJM and transmission owners, and/or other forms of research and analysis.
- **Transmission upgrades in one zone can be triggered by load growth in a different zone**. Some upgrades in states other than Maryland/DC could be triggered, at least in part, by load growth in Maryland. Similarly, some upgrades in Maryland could be triggered, at least in part, by load growth in other states. The proposed approach of focusing on transmission projects physically located in Maryland implicitly assumes that those two effects offset each other. This is a simplifying assumption. The method could potentially be made more accurate, with additional effort and related cost, by requiring assessment of which PJM projects – regardless of the state in which they are located – are related to Maryland peak load growth. Such a refinement may be appropriate in the future once initial experience with the simplified focus on just Maryland-located projects is gained.
- **Difference between deferred and avoided investment**. JMEU requested additional discussion of how long T&D benefits may accrue within the context of a BCA. Specifically, they requested that some emphasis be placed on the difference between deferred and avoided incremental capital investment. With respect to the avoided transmission capacity benefit, JMEU questioned whether the recommended methodology's approach to assigning benefit every year of a new DER or DER program life implicitly assumes that "the otherwise incurred T&D investment is permanently avoided" when they may only be deferred for several years. The Consultant Team provided several reasons why the recommended methodology should address the JMEU's potential concerns. First, the proposed method estimates an average annual cost per unit of load growth. No individual transmission project is assumed to be avoided (or deferred). The average cost is simply used as a proxy for the average transmission benefits of system-wide DER deployment. Second, the extent to which costs might be deferred or avoided will be a function of the volume of

peak demand reduction produced by a DER initiative. Consider a hypothetical calculation in which transmission capital investments are forecast to be $50 million per year associated with 100 MW of annual peak load growth. Assume a 50-year average asset life and 5% real carrying charge that translates to an annual transmission cost of just over $27/kW-year. By definition, if a DER initiative is designed to achieve annual peak demand reductions of 25 MW per year (i.e., one quarter of the forecast peak load growth), the method would not result in an assumption that all of the capital costs are avoided; it would instead be implicitly assuming that either (A) only a portion of the capital investments could be avoided and/or (B) that some or all of the costs can only be deferred. Third, most transmission capital investments are likely to be assumed to have very long lives – e.g., 50 years or more. Under the proposed method, initial capital costs would be annualized over those 50+ years. Most DERs will have much shorter lives (e.g., 10 years for an average efficiency measure). Thus, the DERs will typically be assumed to offset only a portion – and potentially a modest portion – of the capital costs (again, more analogous to capital cost deferral rather than avoidance). Indeed, under the hypothetical described here, a 10-year DER that reduced peak demand by 25 MW would have a net present value of a little more than $6 million – or a very modest fraction of the $50 million on which the avoided transmission cost estimate was based.

- **Summer vs. winter peak demand growth**. With demand in some areas potentially already winter peaking, and the prospect of electrification of space heating further increasing winter peak demand, there is merit to assigning transmission cost value to both summer and winter peak demands as described in Steps 2, 3 and 4 above.[42] However, it is important that benefits do not get double-counted. To address that concern, the recommended method proposes that transmission costs be allocated to *either* winter peak demand growth *or* summer peak demand growth (and not both). The Consultant Team recognizes that this may not always be easy, as some investments may be designed to address both winter and summer peak demands. In such cases, judgement will be required to allocate costs to each season. The Consultant Team also recognizes that a reduction in just summer peak demand (or just winter peak demand) will not eliminate the need to build transmission capacity that is designed to address both summer and winter peak load growth. However, many (if not most) DERs will provide both summer and winter peak demand benefits (even if not in equal measure). More importantly, the proposed method is only designed to assign an average value to reducing (or increasing, in the case of electrification) transmission costs. It is not designed to assess the value of deferring a particular capital investment. In that context, the proposed method is reasonable.

Timeline for Adoption and Interim Method

The recommended method requires both detailed forecasts of capital investments and load growth, as well as estimation of the portion of capital investments that are related to summer and/or winter peak load growth. Because there is some complexity to the analysis,

[42] This conclusion is supported by the April 2025 EmPOWER Seasonal Capacity Working Group Report (https://drive.google.com/file/d/1UTBHu-qw04SuNv2oW4p_htacCg7eLtf_/view).

the recommended method should not be expected to be universally applied until up to a year after it is formally approved. However, it can be used sooner if utilities can do so.

In the interim, the Consultant Team recommends that the most recent EmPOWER assumptions be used.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

There is consensus on the proposed methodology with the EmPOWER IE, OPC and the JMEU all stating support for it and no stakeholder opposing it.

Both parties who commented on the implementation timeline (JMEU and EmPOWER IE) supported the proposal.

The JMEU requested that the interim method for system-wide DER investment include the option of values based on "utility specific calculation consistent with previous filings." The Consultant Team is concerned that this utility-specific calculation may not be indicative of marginal costs that can be avoided, that offering such an option would likely lead to inconsistency across utilities and DERs, and that there may not be transparency in how such values would be derived.

4.2.4. Electric Distribution Capacity Costs

Definition

Electric distribution capacity costs are the costs associated with delivering electricity from the transmission system to individual electric utility distribution customers.[43] They are predominantly the capital costs that are incurred to ensure that the delivery capacity of the distribution system is sufficient to meet the peak demands of customers.[44]

There are three scenarios in which the potential value of avoiding or deferring electric distribution capacity costs should be considered in benefit-cost analysis (BCA) of DERs:

1. System-wide DER initiatives in involving programs offered to all electric customers;
2. Targeted, but not site-specific DER initiatives in which electric DER programs or initiatives are deployed across only portions of the distribution system (e.g., those experiencing and/or forecast to experience demand constraints) but are not designed or optimized to defer any specific, individual capital investments; and
3. Non-wires solutions (NWS) in which EE, DR, DG and/or storage are targeted to a specific geographic area in order to defer or avoid a specific distribution system investment.

Recommended Method – System-Wide DER Initiatives

For system-wide DER initiatives, electric distribution system capacity cost impacts should be estimated using the Ratio of Cost to Load Growth method using the following steps:

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[43] For purposes of this report, transmission capacity costs are defined as those incurred by PJM while distribution capacity costs are those planned for and incurred by distribution utilities. Under this definition, what are sometimes called sub-transmission facilities may be included as distribution system costs.

[44] This includes investments necessary to ensure that voltage levels can be maintained within an acceptable range, i.e. Distribution Voltage management.

1. Estimate future capital investments planned to address peak load growth in the distribution system. This should be a utility-specific estimate based on each utility's forecast needs. It should ideally be based on at least a five-year forecast, with longer time horizons being preferable (if practical). Analysis and judgment will likely be required to determine which projects are related, at least in part, to peak load growth.
2. Identify the portion of the distribution system costs identified in Step 1 that are associated with summer peak load growth vs. winter peak load growth. To the extent that some projects are needed to address both summer and winter peak demands, judgment will be needed to reasonably allocate projects costs to each season. For such projects, it may be appropriate to assign half of project costs to each season.
3. Estimate both summer and winter peak demand load growth on the distribution system[45] for the period of time covered by the distribution cost forecast.
4. Divide the estimated cost of future summer and winter load growth-related investments from Step 2 by the estimated summer and winter peak load growth from Step 3. Estimates should be expressed in terms of $/kW.
5. Annualize capital costs by multiplying the total cost per peak kW of load growth developed in Step 4 using a real levelized carrying charge over the cost-weighted average life of the growth-related capital investments identified in Step 4.

Recommended Method – Targeted (but not Site-Specific) DER Initiatives

When DERs are to be targeted to portions of the distribution system but not specifically designed to defer individual capital investments, the recommended method for estimating system-wide impacts above should be modified so that only capital costs forecast for the targeted areas are divided by forecast load growth for just those areas.

Recommended Method – NWS

As discussed in Subsection 4.2.3 above, the potential economic benefit of an NWS should be estimated based on the specific investment being deferred or avoided. The approach specified in Subsection 4.2.3 for estimating transmission capacity costs also applies to distribution capacity costs.

Key Issues

A range of issues associated with the development of system-wide distribution system costs were discussed with the TMS. Many are similar to those discussed above in Subsection 4.2.3 regarding transmission costs. They include:

- **Low peak load growth scenarios**. As discussed in Subsection 4.2.3, the issue of circumstances with no load growth (i.e., dividing costs by zero) or very low peak load growth was raised. In such circumstances, the approach can be modified to (A) address only areas experiencing peak load growth (i.e., dividing forecasts costs in such areas by growth in peak demand in such areas); and (B) computing a system-weighted average cost based on the portion of total system peak demand associated

[45] Since the purpose of this method is to estimate the distribution system benefit of DERs, distribution system costs should be divided by just growth in distribution system peak demand. Peak demand growth from very large customers (e.g., data centers) that connect directly to transmission will affect transmission system costs but not distribution system costs.

with such growth areas and the portion of total system peak demand associated with areas without peak demand load growth (and therefore zero peak load growth related costs). For example, if the levelized distribution capacity cost in growth areas is $200/kW-year, total system peak demand is 2000 MW, and the growth areas contribute 500 MW (25%) to total system peak demand, the system-weighted levelized distribution capacity cost would be $50/kW-year (i.e., $200 * 25%). This conceptual approach is discussed in more detail in the gas distribution cost subsection below.

- **Challenges with determining which planned distribution system projects are related to load growth**. Similar to transmission investments, while some electric distribution investments are clearly not related to load growth and some are clearly driven entirely (or almost entirely) by load growth, there are others for which addressing load growth is just one of several factors driving the investments. In such cases, judgement will be required when determining the capital cost to include Step 1. It could be reasonable to assign a portion of the capital cost of such a project to load growth – again, based on expert judgment of the importance of load growth as a factor in project. Such determinations will likely require discussions with distribution system engineers and/or other forms of research and analysis.
- **Summer vs. winter peak demand growth**. With demand in some areas potentially already winter peaking, and the prospect of electrification of space heating further increasing winter peak demand, there is merit to assigning distribution capacity cost value to both summer and winter peak demands as described in Steps 2, 3 and 4 above.[46] However, it is important that benefits do not get double-counted. To address that concern, the recommended method proposes that distribution capacity costs be allocated to *either* winter peak demand growth *or* summer peak demand growth (and not both). The Consultant Team recognizes that this may not always be easy, as some investments may be designed to address both winter and summer peak demands. In such cases, judgement will be required to allocate costs to each season. The Consultant Team also recognizes that a reduction in just summer peak demand (or just winter peak demand) will not eliminate the need to build distribution capacity that is designed to address both summer and winter peak load growth. However, many (if not most) DERs will provide both summer and winter peak demand benefits (even if not in equal measure). More importantly, the proposed method is only designed to assign an average value to reducing (or increasing, in the case of electrification) distribution capacity costs. It is not designed to assess the value of deferring a particular capital investment. In that context, the proposed method is reasonable.
- **Capacity additions are lumpy and can be a function of decades of load growth, so dividing five years of capital costs by five years of load growth may present an inaccurate assessment of the value of reducing load growth**. It is certainly true that growth-related capital investments planned for a particular five-year period – the value in the numerator of the proposed method – could be the result of decades of load growth rather than just the five years of load growth included in the

[46] This conclusion is supported by the April 2025 EmPOWER Seasonal Capacity Working Group Report (https://drive.google.com/file/d/1UTBHu-qw04SuNv2oW4p_htacCg7eLtf_/view).

denominator of the proposed method. However, it is equally true that the load growth included in the denominator will contribute to capital projects that are not included in the numerator because they will occur (or have already occurred) outside the five-year analysis period. Thus, the recommended approach may be somewhat "lumpy," i.e., potentially overstating costs per unit of peak demand in some cases, while understating costs in other five-year periods. Over years of DER investment, this lumpiness should balance out. The lumpiness could be reduced if the analysis period were increased to more than five years (e.g., 10 years). The choice of five years is made here to align with current utility planning efforts.

- **Peak hours on parts of the distribution system may not be exactly the same as system peak hours**. Not all elements of the distribution system peak at the same time of a given season. For example, some summer-peaking substations may typically experience peak demand at 4 pm while others may experience it at 7 pm.[47] When analyzing NWSs targeted to specific distribution system investments, the exact times of peak demand and the ability of DERs to deliver load reductions in those hours should be part of the required customized analysis of cost-effectiveness. However, for the computation of *average* distribution system benefits of *system-wide* DER initiatives, it is not practical to compute potential benefits associated with peak load reductions for different hours of the day in summer and winter. The recommended method makes the simplifying assumption that summer and winter peak demands on the distribution system occur at the time of seasonal system peaks. JMEU recommended that peak demand growth estimated in Step 3 be the sum of growth in maximum demand across each distribution circuit rather than the growth in demand at the time of system peak. However, that would mean that the avoided distribution capacity cost (in $/kW-year) would be based on load impacts for a different mix of hours than those for which average DER impacts are typically estimated. Further, it would not be easy to compute weighted average DER impacts for the mix of hours on which distribution circuits experience peak demands. Finally, even if possible, it is not clear that much more complex estimates of average DER impacts on the range of distribution system peaks would materially change their value. That said, future analysis may be merited to determine the extent to which the Consultant Team's recommended method over- or under-estimates impacts on distribution system costs for one or more DERs. If the error is significant enough to merit concern, the approach can be modified in the future.
- **Magnitude of reductions in peak load growth may not be sufficient to defer or avoid capital investments**. JMEU also raised this concern. In response the Consultant Team notes that the recommended method for system-wide initiatives does not assume any particular capital investment will be deferred or avoided. It simply computes an average value per kW of peak load reduction (or increase in the case of electrification). In that context, it would be problematic to assume that there is no value to each of many different DERs because each by itself may not be large enough to significantly affect costs. It is the combined effect of multiple DERs installed over

[47] For insight into how distribution system capacity needs typically occur over a range of summer and winter hours, see Demand Side Analytics, Avoided Cost of Transmission and Distribution Capacity Study, prepared for the Pennsylvania Public Utilities Commission, July 2024 (https://www.puc.pa.gov/pcdocs/1855615.pdf).

multiple years that ultimately determines the magnitude of distribution system cost impacts. Any one of those multiple DER "building blocks" could provide the increment of peak load reduction that enables a particular capital investment to be deferred another year.

Timeline for Adoption and Interim Method

The recommended cost-to-load growth method for system-wide DER analyses requires both detailed forecasts of capital investments and load growth, as well as estimation of the portion of capital investments that are related to summer and/or winter peak load growth. Because there is some complexity to the analysis, the recommended method should not be expected to be universally applied until up to a year after it is formally approved. However, it can be used sooner if a utility has the ability to do so.

In the interim, the Consultant Team recommends that the most recent EmPOWER assumptions be used.

For targeted, but not site-specific (i.e., not NWS) DER investments, an interim strategy could be to scale the system-wide EmPOWER assumptions to the portions of the system being targeted for DERs if the targeted areas are expected to represent the vast majority of forecast capital investments in the near to medium-term. For example, if the system-wide avoided distribution capacity cost is $50/kW-year, and a targeted DER initiative is focused on the 25% of the system that is most demand constrained, an interim assumption of the value of DERs in those portions of the system could be estimated to be $200/kW-year (i.e., $50 / 0.25). This may somewhat overstate the benefits in the targeted area because there are likely to be some capacity deferral benefits in the other three-quarters of the system, at least in the longer-term, but it could still be a reasonable interim approach until more detailed analysis of the targeted areas can be completed.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

The EmPOWER IE, OPC and JMEU all support the proposed methods. Stack Energy and MEA both supported the proposed method, except that they suggested the method should require use of a 10-year distribution system forecast rather than the minimum of 5 years and just a preference for 10 years in the recommendation. However, the Consultant Team did not believe it was appropriate for the decision on the minimum distribution planning period to be driven by UBCA methodology (as opposed to the distribution planning process itself).

With regard to Steps 1 and 2 of the proposed methodology for system-wide DER initiatives, MEA also wanted the recommendation to "require utilities to document…the screening criteria used to identify load-growth-related capital, the allocation methodology for mixed purpose projects, and specific projects included and excluded from the numerator" and to make clear that stakeholders "should have discovery rights on inputs and assumptions through the ESP filing process." While these may be reasonable suggestions, the Consultant Team has not included them in the formal recommendation as they were seen as potentially outside of the Consultant Team's scope of proposing technical methodologies.

The EmPOWER IE supports implementation timeline and interim approach. The JMEU also supports the interim approach for system-wide DER initiatives, but requested that the interim method for targeted but not site-specific DER investment to include the option of values based on "existing utility work calculating representative costs for system construction." The Consultant Team is concerned that "representative costs for system construction" may not be indicative of marginal costs that can be avoided, that offering such an option would likely lead to inconsistency across utilities and DERs, and that there may not be transparency in how such values would be derived.

4.2.5. Electric Distribution Operation and Maintenance (O&M) Costs

Definition

These are costs that are expensed each year to maintain a well-functioning grid. They include but are not limited to servicing of transformers and other equipment, tree trimming to reduce risk of downed power lines, and repair of downed lines.

Recommendation

The recommendation is to consider electric distribution O&M cost impacts *from DERs* as not material. While annual distribution O&M expenses can be significant, a review of the literature found little information on the marginal impact of DERs on such costs and the information that exists suggests such impacts are not material. For example, one study of the impacts of distributed generation on utility distribution system costs concluded that available data on marginal O&M costs "exhibit extreme volatility" and that there was "no clear basis…to tie marginal O&M expenses to marginal plant investments." As a result, the study did not include marginal O&M costs in its analysis and focused instead only on distribution capital costs. [48]

Note that this recommendation is a proposed change to the UBCA Phase I recommendation.

Extent of Agreement within UBCA Work Group – **Consensus**

The JMEU, OPC and EmPOWER IE support the proposal. No stakeholder expressed opposition to it.

4.2.6. Electric Transmission and Distribution (T&D) Line Losses

Definition

T&D losses are the difference between the amount of electric energy produced at generation facilities and the amount of energy consumed at customers' meters. A portion of losses are incurred to just energize the system and are relatively fixed (typically about 25% of annual losses). The rest are resistive losses that are caused by friction released as heat. Resistive losses grow exponentially with load. As a result, average loss rates at peak hours are substantially higher than average loss rates over an entire year.[49] In addition, marginal loss

[48] Shirley, Wayne (Regulatory Assistance Project), Distribution System Cost Methodologies for Distributed Generation, September 2001 (https://www.raponline.org/wp-content/uploads/2023/09/rap-shirley-distributioncostmethodologiesfordistributedgeneration-2001-09.pdf).

[49] An average loss rate is the total kWh losses experienced divided by total kWh generated. Annual average energy losses divide the sum of all losses incurred in every hour of the year by the sum of all kWh generated in every hour of the year. Average peak losses are the total losses experience on just system peak hour(s) divided by total generation on system peak hour(s).

rates – both at peak hours and all other hours – are higher than average losses for any given hour.[50]

Recommended Method

Marginal loss rates should be estimated for both (A) average annual energy impacts; and (B) peak demand impacts of DERs. One of two different approaches should be used to estimate both marginal average annual energy and marginal peak loss rates:

1. **A statistical analysis of the relationship between losses and load**. The analysis would be based on historical utility sales (customer load) and generation data for each hour over one or more recent years. A regression analysis, using hourly sales as the independent variable and losses as a dependent variable, would establish how losses (i.e., the difference between generation and sales) change as load grows.[51] The marginal energy loss rate could be estimated by inserting first (A) the average annual hourly customer sales and then (B) a small (e.g., 2%)[52] reduction of the average annual hourly customer sales into the regression equation that was developed using historical utility data. The difference in losses divided by the difference in sales would be the marginal energy loss rate. The marginal loss rate for peak hours would focus on marginal loss rates during hours of system peak demand. It would be estimated by inserting both (A) the peak hour customer load and (B) a 2% reduction to peak hour customer load into the regression equation. The difference in losses divided by the difference in sales would be the marginal energy loss rate.
2. **Use of Simplified Multipliers**. The alternative to a statistical analysis would be to apply multipliers to convert average annual (non-marginal) loss rates – a value that all electric utilities should have – to both marginal loss rates for energy and marginal loss rates for peak hours. Based on analyses in other jurisdictions,[53] it is recommended that marginal transmission loss rates be assumed to be the same as average transmission loss rates. However, marginal loss rates for the distribution system are considerably higher than average loss rates, especially on peak hours.[54] The following multipliers are recommended to be applied to average distribution loss rates:

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[50] Marginal loss rates represent the impact of adding or subtracting demand in a given hour or set of hours. Marginal loss rates are the appropriate rates to use when estimating DER impacts because DER investments affect whether demand for electricity will be just a little higher or a little lower in a given set of hours.

[51] Other independent variables could potentially also be considered in a statistical analysis.

[52] The DTE study referenced below used a 2% change to estimate marginal impacts. That level of change is roughly consistent with the range of annual energy savings that the EmPOWER programs have been achieving in recent years.

[53] See: Ariel Crowley et al. (Guidehouse), "Marginal Line Loss Rate Calculation for Non-Wire Alternative Benefit Cost Model", memorandum sent to Kevin Stewart et al. (DTE Energy), December 9, 2021 (not available online, but provided to Technical Methods Subgroup) and Commonwealth Edison, 2018-2021 Energy Efficiency and Demand Response Plan (Appendix A), filed in Illinois Commerce Commission Docket 17-0312 (https://www.icc.illinois.gov/docket/P2017-0312/documents/254601/files/449637.pdf).

[54] See: Ariel Crowley et al. (Guidehouse), "Marginal Line Loss Rate Calculation for Non-Wire Alternative Benefit Cost Model", memorandum sent to Kevin Stewart et al. (DTE Energy), December 9, 2021 (not available on-line, but provided to Technical Methods Subgroup) which found that the average distribution loss rate was 5.36%, the average marginal distribution loss rate was 8.04% (or 1.5 times the average annual loss rate) and the average marginal peak loss rate was 24.57% (or 4.58 times the average annual loss rate) and Commonwealth Edison, 2018-2021 Energy Efficiency and Demand Response Plan (Appendix A), filed in Illinois Commerce Commission Docket 17-0312 (https://www.icc.illinois.gov/docket/P2017-0312/documents/254601/files/449637.pdf) which found that the average annual marginal line distribution loss rate was 1.65 times the average loss rate and that the peak distribution loss rate was 1.96 times the average annual loss rate (yielding a marginal peak loss rate of 3.23 times the average annual

a. **Average marginal energy loss rate:** 1.5 times the utility-specific average annual energy loss rate; and
b. **Marginal loss rate for peak demand:** 3.0 times the utility-specific average annual energy loss rate.

All marginal loss rates should be utility-specific (not a statewide average). If a utility has completed a statistical analysis (option 1), the results from that analysis should be used. However, in the proposed method, utilities may use simplified multipliers (option 2) instead of conducting a statistical analysis or until a statistical analysis has been completed.

Note that if losses are expressed as the percent of energy generated that does not reach customers, then reductions of load at customers' meters would need to be multiplied by 1/(1 – the marginal loss rate) to convert customer load reductions to reductions in output required from generators. For example, if on the margin 10% of energy produced by generators does not reach customers, then 1 kWh of reduced consumption at customers' meters is equal to 1.11 fewer kWh [1 kWh* 1/(1 – 0.10) = 1.11 kWh] that generators have to produce.

Ultimately, avoided capacity costs, avoided energy costs and avoided T&D capacity costs, when expressed as costs to supply capacity and energy to the grid, should be multiplied by 1 plus the applicable (energy or capacity) marginal loss rate. For example, if the avoided capacity cost, expressed as the marginal cost of supplying additional generation to the grid, is $100/kW-year, and the marginal loss rate for peak demand is 20%, then the value of reducing a kW of peak demand at a customer's meter would be $120/kW-year.

Note that it is possible – depending on how PSM ultimately implemented – that the effect of transmission losses will be included in PSM outputs on electric energy costs, electric generation capacity costs, GHG emissions and other factors. To the extent that is the case, it will be important to not apply transmission loss factors a second time outside of the PSM so as to not double-count such impacts.

Key Issues

Discussion on the recommended methods focused primary on the following two issues.

- **Use of a single weighted average value for all customers versus development of different marginal loss rates for customers connected to the grid at different points in the T&D system**. Though marginal loss rates will differ for customers connected to the grid at different points in the T&D system (particularly for those connected to the transmission system instead of the distribution system), the level of increased accuracy may not be worth the added analytical complexity for system-wide DER initiatives. Thus, the recommended method is to use a single average marginal loss rate for energy and a single average marginal loss rate for peak for all customers served by such initiatives.
- **Allowing the option of either a statistical analysis or simplified multipliers**. MEA raised concerns about whether the simplified multipliers should be allowed, as they will be less accurate than values derived from Maryland-specific statistical analyses.

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loss rate). See also: Lazar, Jim and Xavier Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, published by the Regulatory Assistance Project, August 2011 (https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-eeandlinelosses-2011-08-17.pdf).

While that is true, the physical principles underpinning the relationship between average and marginal losses suggest that Maryland-specific analyses are unlikely to produce very large differences in BCA results relative to the use of multipliers. Thus, the Consultant Team believes allowing the option of either method strikes a reasonable balance between accuracy and cost or effort.

Timeline for Adoption and Interim Method

Given the amount of data to analyze and some potential complexities to the analysis, option 1 of the recommended method (statistical analysis of the relationship between load and losses) may not be possible until up to a year after it is formally approved by the Commission (if it is approved). However, it can be utilized sooner if a utility has the ability to do so. However, option 2 (use of multipliers to average annual loss rate) can be applied immediately and could be used by any utility that is not yet ready to use option 1.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

The EmPOWER IE, OPC and JMEU all support the proposed method.

MEA supported use of the statistical analysis approach but suggested it should be the only option and that the multiplier method should not be permitted.

Both parties who commented on the implementation timeline (JMEU and EmPOWER IE) supported the proposal.

4.2.7. Ancillary Services Costs

Definition

Ancillary service are those services required to maintain electric grid stability, including regulation and reserves, among others.[55] To maintain stable frequency, regulation matches generation with very short-term changes in demand by moving resource output up and down via automatic signals. Operating reserves supply electricity when the grid has an unexpected need for more power on short notice. In PJM, operating reserves include synchronized, primary and thirty-minute reserves. A DER's net effect on ancillary services depends on its load profile and the system conditions during operation. A DER that participates in the ancillary services market creates value as represented by the ancillary service price.

Recommended Method

Ancillary service effects should be determined using a "historical price approach." For DER programs that are eligible and intend to participate in PJM regulation or reserve markets, that approach follows these steps:

1. Determine project-specific service capacity (MW) (e.g., MWs of DER bid into the ancillary service market)
2. Determine project-specific annual hours of anticipated service (hours) (e.g., forecast hours of operation for DER)

[55] E.g., reactive power services and black start services, which are dealt with at PJM outside of a standard market structure and are not included in consideration of this impact in the MD-UBCA Test.

3. Source the two-year historical average for service price ($/MWh) (e.g., PJM two-year average synchronized reserve price)
4. Multiply all three values to determine cost effect ($/MWh).

Key Issues

The historical price approach outlined above leverages historical price data and is narrowly tailored to only reflect the potential cost effects of projects or programs that will be explicitly bid into the ancillary service market. This approach is similar to one that Con Edison uses for its electric benefit cost analyses.[56]

The Consultant Team explored this historical price approach as well as two other potential pathways. The first of these other pathways was to assign no impact under the assumption that ancillary service cost impacts are too minor to assess. This approach was deemed outdated and unlikely given the active participation of some DERs in the ancillary services markets. The second of these other pathways was to utilize PSM to determine ancillary service price forecasts in addition to energy, capacity, and emissions. This is possible but is highly cost and time intensive. Modeling has been used in some limited scenarios in Texas and Hawaii,[57] and the California Public Utilities Commission uses SERVM modeling to determine ancillary service outcomes.[58] However, these assessments are labor intensive and require careful calibration to existing markets that is not necessary to assess the potential cost effect associated with ancillary services.

JMEU responded to this proposed method by stating that "a dispatch model such as BStore (that BGE and Brattle currently use to simulate dispatch for storage projects) co-optimizes for energy and ancillary services based on forecasts for energy prices and (ancillary services)…therefore the projected hours of anticipated service may change from year to year over the measure life of the program being considered and may not be a static annual value." The Consultant Team recognizes BStore as a useful tool that is appropriate to continue to use to estimate expected number of hours of annual service for each DER (i.e., to develop the values required for step 2 in the recommended method above). The Consultant Team also agrees that forecasts of hours or use assumptions could vary by year and do not need to be assumed to be constant over time.

Finally, the recommended approach only applies to DER programs eligible and intending to participate in regulation or reserve markets. This wording was taken directly from a utility

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[56] Con Edison Electric Benefit Cost Analysis Handbook, Version 5.0, June 2025, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF079C297-0000-C730-8944-C9846FA6BB58%7D&DocTitle=CECONY%202025%20BCA%20Handbook

[57] ERCOT, Cost Benefit Analysis of ERCOT's Future Ancillary Services Proposal, December 2015 (https://www.ercot.com/files/docs/2015/12/21/667NPRR_12a_Cost_Benefit_Analysis_122115.pdf); and Hawaiian Electric, Advanced Rate Design Final Proposal, Docket No. 2019-0323, March 15, 2021 (https://shareus11.springcm.com/Public/DownloadNative/25256/4b8b0806-6c0d-ee11-b83b-48df377ef808/d1893b41-530e-ee11-b83b-48df377ef808).

[58] Energy and Environmental Economics, 2024 Distributed Energy Resources Avoided Cost Calculator Documentation, for the California Public Utilities Commission (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/updated-2024-acc-documentation-v1b.pdf https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/updated-2024-acc-documentation-v1b.pdf).

recommendation, and the Consultant Team agreed that any assessment of other programs would be inappropriate.

Timeline for Adoption and Interim Method

This approach can be adopted immediately for all DERs that may be bid into the regulation or reserve markets (which may include DR, DG, storage, and/or EV resources). Otherwise, effects are assumed to be immaterial.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus within the UBCA work group on this recommendation, with both OPC and JMEU expressing support and no party expressing opposition.

4.2.8. Electric Utility System Risk

Definition

There is uncertainty associated with many aspects of future utility system costs. Along with that uncertainty is the risk of adverse (i.e., high cost) outcomes. Uncertainty can be addressed in forecasts of energy, capacity and other utility system costs through probability-weighting of a range of potential future scenarios. However, that is uncommon in forecasts used for DER benefit-cost analyses, which typically rely on a single “best estimate” of what the future will hold. Moreover, probability-weighting arguably does not account for the full value of reduced risk; because most customers are risk averse, there is inherent value in reducing exposure to the *worst* potential outcomes.

DERs are commonly considered to be risk mitigating for a range of reasons including:[59]

- Reducing exposure to future energy and capacity price uncertainty (if a DER reduces demand);
- Reducing exposure to the cost of future environmental regulations (if a DER reduces emissions);[60]
- Providing “option value” – i.e., slowing load growth which buys time to recalibrate needs assessments and allows for the emergence of lower cost solutions;
- Diversifying the resources relied upon to meet customers’ electricity needs; and
- Increasing the modularity and flexibility of utility resources – i.e., when relying on 100 different DERs instead of 1 major traditional supply-side resource, you both reduce exposure to significant cost overruns or malfunctions/outages by “not putting all your eggs in one basket” and by retaining the ability to shift emphasis from lesser performing DERs the better performing DERs.

[59] Several of these risks are related to policy concerns expressed as interests in “energy security”.
[60] Such potential future environment compliance costs would not be embedded in current energy or capacity price forecasts.

While there are risks associated with DERs (e.g., performance risk) as well as traditional supply-side alternatives, most experts agree that "net risk" is lower with DERs for the reasons stated above.[61] There is economic value associated with any such net reduction in risk.[62]

Recommended Method

The Consultant Team recommends use of the following "adders" as defaults for valuing risk impacts of DERs:

- 10% of all electric generation and T&D cost reductions resulting from energy efficiency, distributed generation, and distributed storage initiatives and cost increases resulting from electrification initiatives; and
- 5% of electric generation and T&D cost reductions resulting from demand response initiatives.

The proposed adder for demand response is half of that proposed for other DERs both because (A) demand response primarily helps addresses capacity and potentially T&D cost uncertainty (and not energy price uncertainty); and (B) it is a potentially less durable resource in that customers can easily opt in or opt out from year to year (whereas most efficiency or distributed generation investments are in hardware – such as an efficient air conditioner, attic insulation upgrade or PV panels – that once installed will typically last and produce energy and capacity benefits for a decade or two).

Alternatively, utilities can exercise the option to quantify risk through scenario analyses or other studies, provided that such analyses or studies address multiple ways in which DERs materially affect risk, assign probabilities to different possible outcomes, and assign value (beyond just probability-weighting) to the benefit of avoiding the worst cost outcomes. To the extent that risk is partially captured through other approaches, that should be documented and the recommended adders adjusted as needed to avoid double-counting of risk impacts. For example, EmPOWER currently includes a risk premium in its estimate of avoided energy costs.[63] In that case, the 10% risk adder for efficiency and electrification would only be applied to the value of avoided capacity and avoided T&D costs.

Key Issues

While there is general agreement that DERs are likely to reduce risk, there are questions about the magnitude of such benefits and whether the proposed use of risk adders is supported by a sufficient level of empirical evidence. Quantifying and monetizing the impact of DERs on risk in a standardized way is challenging, both because of the range of ways in which DERs affect risk and the inherent difficulties in assigning value to each of those effects.

That said, there are examples of efforts in other jurisdictions to assign value to the risk mitigating benefits of DERs. For example, the New England AESC study has estimated what

[61] See Table 6-2 in National Association of State Energy Officials (NASEO), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, 2026 (https://naseo.org/Data/Sites/1/media/tknaseo/nspm-main-2026-final.pdf).

[62] Note that by adding load to the grid, electrification will increase electric system risk. However, it will simultaneously reduce risk to the gas utility system (if switching from gas to electricity) and/or to customers currently consuming other fuels (e.g., fuel oil, propane, gasoline).

[63] For example, see Cadmus, EmPOWER Maryland 2024 Cost-Effectiveness Results Report, February 17, 2026 (https://docs.google.com/document/d/1_jsqD9SdcJlfXxba8qsOQ2RrtltXDTcO/edit).

it calls a "wholesale risk premium" to account for the difference in wholesale market prices (i.e., the values for electric energy costs that would be estimated using PSM, as discussed above) and the prices retail suppliers charge under fixed price contracts. The 2024 AESC report states that such premiums, based on confidential contracts with terms between 6 months and 3 years, range from less than 5% to 10% (i.e., fixed price contracts tend to be 5% to 10% higher than wholesale prices). The AESC study uses 8% as an average. However, it notes that three years is the longest fixed price contract term it analyzed because that "appears to be the limit of suppliers' willingness to offer fixed prices,"[64] which implies that the premium would likely be larger for longer-duration contracts. That observation is important because many DER investments can be seen as analogous to long-term (10, 15, 20 years or, depending on the DER), fixed price contracts. For example, insulating the attic of a home or installing PV on a customer's roof will produce essentially the same annual reduction in kWh drawn from the grid every year over the next 20+ years for a known up-front cost.

Another notable example is Vermont's 10% cost "subtraction" (rather than electric benefits "adder") to cost-effectiveness analysis of efficiency programs since 1990. In the order establishing this practice, the Vermont Public Service Board stated that this is likely a conservative accounting for the risk mitigating benefits of efficiency programs.[65]

In short, there is limited empirical data on the magnitude of the risk mitigating benefits of DERs, and there is also reason to believe that proposed adders are reasonable, if not conservative.

Timeline for Adoption and Interim Method

Because of its simplicity, this recommendation can be adopted immediately.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

OPC and EmPOWER IE support the proposal. The JMEU supports the proposal with the caveat that it would like the report to include information supporting the recommended adder values, which the Consultant Team has endeavored to do in the discussion of Key Issues above. The JMEU also suggests that the risk adder be applied not only to utility system impacts but to host customer impacts as well. The Consultant Team disagrees for several reasons. First, the adder is intended to account for the effect DERs have on key utility system risks (e.g., future fuel price uncertainty). In that context, it is unclear why the impact of a DER on such risks would have any relationship to host customer capital costs. Second, in most cases, it is anticipated that DERs will reduce utility system risk. In such cases, multiplying the risk adder by what will typically be a host customer *increase in cost* to install a DER (rather than a capital cost savings) which would have the effect of assigning less value (and maybe even negative value) to risk reduction (i.e., the opposite of its intended purpose).

[64] AESC, pp. 354-355.
[65] Vermont Public Service Board, Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy, Docket No. 5270, April 16, 1990.

4.2.9. Electric Utility System Reliability

Definition

Reliability is the ability to maintain power delivery to customers in the face of routine uncertainty in operating conditions, as in cases of fluctuating load and generation, fuel availability, and outage of assets, all under normal operating conditions. For this effort, reliability is considered applicable to events which last no longer than 24 hours. A shorter time frame distinguishes reliability events from resilience events, as discussed in Subsection 4.2.10. 24 hours is used here as a result of availability of survey data on that timescale, as described below.

Both reliability and resilience have a set of differing definitions based on jurisdiction and preferred approach. The definition used here is informed primarily by the 2022 NESP Methods, Tools, and Resources (MTR) Handbook, SEPA's Beyond the Baseline: Measuring Resilience Report, and EPRI's Metrics to Evaluate Effectiveness of Resilience Strategy Deployment report. The 24-hour time increment is a result of available survey data, described below.

Recommended Method

Utility system reliability should be determined using the Reliability Assessment Framework approach only for DER programs (a) explicitly designed to affect system reliability, or (b) for which utilities currently collect the metrics described below:

1. Quantify estimated utility system impacts of specific programs.
    - Determine the number of residential and non-residential customers participating in the assessed program.
    - Determine the anticipated SAIDI, SAIFI and/or CAIDI effect of (i.e., changes resulting from) the targeted program.
2. Calculate economic value of changes in reliability metrics using LBNL's ICE calculator
    - Utilize two of the above metrics (SAIDI, SAIFI and/or CAIDI) paired with the number of participating customers to determine the cost effect of assessed programs.

Key Issues

The 2022 NESP MTR Handbook identifies four different methods for assessing cost impacts associated with reliability. The first, the Reliability Assessment, relies on the characterization of reliability potential of DERs as compared to normal operations, and the ability to calculate dollar impacts using existing survey data. The Stated Preferences approach uses new customer surveys in the absence of existing data to assess customer willingness to pay to avoid interruptions. The Revealed Preferences approach relies on the existence of actual customer purchasing behaviors to identify the amount customers have paid to avoid the negative consequences of interruptions (for example, the cost of a behind-the-meter storage system that customers have actually paid to avoid a specific set of normal outages). Finally, Macroeconomic Methods can be used to leverage economic output and employment data, among other indicators, to analyze the effects of outage of regional economies. However, this approach relies on broad assumptions and is better suited for broad economy-wide studies.

The Consultant Team determined that the Reliability Assessment Framework, using LBNL's Interruption Cost Estimate (ICE) Calculator, represented the most straightforward and accurate approach to estimating utility-system cost effects of reliability improvements. The LBNL ICE Calculator is a publicly available tool for estimating customer cost impacts of short-duration power interruptions. It utilizes utility-sponsored customer interruption costs surveys (like those that the Revealed Preferences approach would collect) for events that last up to 24 hours. Of note, the ICE calculator surveys include those run by the majority of Maryland utilities.

Initial verbal feedback when this approach was presented from the OPC stakeholders reflected anecdotal concern with the underlying survey data available via the ICE calculator, primarily that outputs might be inflated. The Consultant Team solicited feedback from the UBCA Work Group for any better resources and received none. Subsequently, the Consultant Team revisited the data to ensure rigor and assess any alternatives. Ultimately, it was determined that the surveys underlying the ICE Calculator represent the most up-to-date and state-specific willingness-to-pay data available.

Timeline for Adoption and Interim Method

This approach can be adopted immediately for all programs that are explicitly designed to affect system reliability, or for which utilities currently collect impact metrics (SAIDI, SAIFI, CAIDI).

Extent of Agreement within UBCA Work Group – **Non-Consensus**

The EmPOWER IE and JMEU support the recommended methodology. OPC opposes the recommendation because of concerns about using the ICE calculator as the basis for estimating the monetary benefits of reductions in short duration outages. OPC suggests that, for at least residential customers, the benefits are mostly about reduced disruption and inconvenience which are "hard to monetize in a way that is reliable enough to drive benefit cost analysis." MEA raised similar concerns. However, no alternative to the ICE calculator has been suggested. The Consultant Team notes that the ICE calculator-estimated benefits to business customers may be larger than for residential customers.

4.2.10. Electric Utility System Resilience

Definition

The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Typically, this can be assessed using three key measures: (1) scale of the disruptive event, or events avoided; (2) duration of the disruptive event; and (3) response, or the speed and quality of the restoration. All three measures must be assessed for resilience events.

Recommended Method

It is recommended that there be no required approach to assess utility system resilience impacts. Where utilities identify programs for which value is expected beyond reliability as calculated using the ICE calculator and for the entire system (i.e., not host customer or societal level), they may pursue a Stated Preferences approach to estimate such resilience impacts.

Under such an approach, the utilities would run tailored surveys to determine the specific stated cost preferences of all utility customers regarding the avoidance of major outages. Surveying would include assessment of tolerance for different durations and scale of such events, and/or the desired speed or quality of recovery. Ultimately, this would enable utilities to compare restoration cost savings before and after DER deployment during similar resilience events.

Key Issues

Available approaches to determining the cost effects of resilience are largely the same as those for reliability: Stated Preferences, Revealed Preferences, and Macroeconomic Methods. The main difference is the consideration of the speed and quality of restoration response during extreme events. Further, at a utility-system level, any cost effects measured need to be additional to those associated with standard reliability. Currently, there are no available standard survey resources associated with resilience, or any events longer than 24 hours. As such, any assessment of utility-system resilience can currently only be assessed on a customized basis. As discussed with the working group, the Consultant Team found that the likelihood of such a DER initiative providing measurable additional resilience benefit to the grid as a whole is relatively low, as such, the optional approach described above is most appropriate.

Timeline for Adoption and Interim Method

The optional approach recommended would only be adopted when utilities and/or the Commission deem it necessary.

Extent of Agreement within UBCA Work Group – **Consensus**

EmPOWER IE, JMEU and OPC all generally agreed with the optional approach. JMEU stated that, if analysis of resilience impacts were to be required, more detail on the proposed methodology would need to be provided. Given the recommendation remains optional and that it would require customization for specific DER initiative designs, the Consultant Team determined that further detail was not practical at this time. OPC expressed concern that DER impacts on resilience may not be large enough to warrant spending money on additional analysis. The EmPOWER IE states that this is not a material impact for EE, but does not oppose it being estimated for other DERs "if it is material and not already in a 'catch all' adder or embedded in avoided costs." Given that this category was identified during Phase I as relevant to the MD-UBCA Test, the Consultant Team determined that keeping this approach optional was sufficiently responsive to this comment.

4.2.11. Credit and Collection Costs

Definition

Credit and collection costs are utility costs associated with customer bill payment challenges. These costs can take several forms including the carrying costs of arrearages, costs of engaging customers who are in arrears, costs of disconnections and reconnections, costs of writing off bad debt and costs associated with bill payment subsidies or discounts. These costs are all ultimately paid by other utility customers.

To the extent that DERs installed by customers can lower their bills, they can improve the ability of customers to pay their bills and therefore reduce utility credit and collection costs. While this conceptually applies to all customers, it is typically considered most significant for DERs targeted to low-income households.

Recommended Method

The primary recommendation for valuing this impact is to apply a 2% multiplier to annual bill savings for low-income customers who receive bill savings of at least $100 per year from DERs installed in their homes. Estimates of annual bill savings would be based on current retail rates and the magnitude of changes in annual energy consumption for the average low-income participant in a particular DER program. For electrification initiatives, the 2% multiplier should be applied to impacts on total energy bills – i.e., the net impact of increasing electric bills and decreasing fossil fuel bills. The annual effect of the 2% multiplier over the life of the DER savings should be converted to a present value (PV) benefit (or cost, if electrification increases total energy costs) using the UBCA approved 2% real discount rate.

For example, if a low-income home weatherization (efficiency) program is projected to save 1000 kWh per year for 25 years on average for each low-income participant in the program, in a utility system with an average residential retail cost per kWh of $0.20, the estimated annual bill savings would be $200 (1000 kWh * $0.20/kWh = $200) and the credit and collection cost savings benefit per participant would be computed as follows:

Annual credit and collection cost savings: 1000 kWh * $0.20 * 2% = $4

PV of credit and collection cost savings (Excel formula): PV(2%,25 years,$4) = $78

This recommendation is consistent with current EmPOWER practice. As Table 14 shows, it is also conservative relative to studies that have been conducted regarding the impacts of low-income weatherization (efficiency) programs.

Table 14: Range of Utility Non-Energy Impacts (NEIs) from Weatherization Programs[66]

NEI Estimates from Multiple Weatherization Studies: Dollar and Percentage Analysis	Dollar NEI Values Range low-high	Typical Values	Percentage NEI Values Range low-high	Typical Values
UTILITY PERSPECTIVE				
Payment-related				
Carrying cost on arrearages	$1.50 - $4.00	$2.50	0.6% - 4.4%	2.0%
Bad Debt write-offs	$0.50 - $3.75	$1.75	0.4% - 2.0%	0.7%
Reduced LI subsidy payment/discounts	$3.00 - $25.00	$13.00	3.9% - 29.0%	16.4%
Shutoff/reconnects	$0.10 - $3.65	$0.65	0.1% - 4.4%	0.5%
Notices	$0.05 - $1.50	$0.60	0.1% - 1.8%	0.9%

[66] Northeast Energy Efficiency Partnership, Non-Energy Impacts Approaches and values: an Examination of the Northeast, Mid-Atlantic, and Beyond, June 2017. Per the footnotes to Table 20 from this report, findings "are based on 20 studies of weatherization programs across the country" and "dollars are added net benefit value per household per year; percentage figures should be applied to the dollar value of the kWh savings."

Customer calls/collections	$0.40 - $1.50	$0.90	0.2% - 1.9%	0.6%
Service-related				
Emergency/safety	$0.10 - $8.50	$2.50	0.1% - 2.7%	0.8%

The low-income bill savings multiplier could be revised in the future based on new research or analysis. New research and analysis could also potentially be used to develop multipliers or other mechanisms for assigning economic value to impacts of DERs on credit and collection costs of non-low-income customers.

Key Issues

The Technical Methods Subgroup discussion of credit and collection costs focused primarily on two issues:

- **The extent to which credit and collection costs reductions can be attributed to DER initiatives**. JMEU acknowledged a conceptual link between lower customer bills and credit and collection costs, but questioned whether there is evidence of a causal link. The Consultant Team observed that studies in a number of different jurisdictions have found such causal links for low-income efficiency programs.[67] While the team is unaware of studies of such impacts for other DERs, there is no reason to believe that the impact of $200/year in bill reduction from a rooftop PV program or some other DER program targeted to low-income households would have a different impact on credit and collection costs than a $200/year bill savings from an efficiency program. Also, as discussed above, the proposed method is to use what is likely to be a conservative multiplier of bill savings, only for low-income participants in DER programs, and only for DERs expected to produce substantial annual bill savings.
- **The minimum low-income bill savings required to assign value to credit and collection cost reductions**. The Consultant Team's preliminary proposal on this issue was to apply the 2% annual bill savings multiplier only to DER initiatives that provide "significant" bill savings. The OPC requested that the proposed method be more specific. The Consultant Team then modified the proposed recommendation to require at least $100/year in bill savings per low-income customer participating. This is consistent with current EmPOWER practice which applies the 2% multiplier only to low-income weatherization.

Timeline for Adoption and Interim Method

The proposed 2% bill savings multiplier involves fairly simply assumptions and calculations and is therefore recommended to be implemented immediately.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus on the proposed methodology with the JMEU, EmPOWER IE and OPC all supporting it and no stakeholder opposing the proposal.

[67] *Id.*

Both parties who commented on the implementation timeline (JMEU and EmPOWER IE) supported the proposed timeline.

4.2.12. Direct Utility Costs to Promote DERs

Definition

Direct utility costs to promote DERs include any rebates or other financial incentives,[68] utility direct investment in DERs (e.g., in voltage optimization spending incurred to reduce energy consumption on the customer side of the meter, or storage on the utility side of the meter), utility marketing costs to promote DERs, utility costs of managing and evaluating DER initiatives and any applicable utility performance incentives.

Recommended Method

All direct utility costs to promote DERs should be estimated for forward-looking benefit-cost analyses (BCAs); for retrospective BCAs, actual utility direct costs should be included.

Key Issues

Treatment of utility direct costs of promoting DERs in BCAs is straightforward and therefore was not discussed within the TMS. Stakeholders provided feedback via comments on draft versions of this report.

Timeline for Adoption and Interim Method

All utility direct costs of promoting DERs should be estimated and immediately included in BCAs of DERs.

Extent of Agreement within UBCA Work Group – **Likely Consensus**

There is likely consensus on recommendations for this issue; no specific comment was provided by any stakeholder in review of this report, but no stakeholder objected or expressed reservations to this item being characterized as “consensus.”

4.3. GAS UTILITY SYSTEM IMPACTS

4.3.1. Gas Energy Costs

Definition

Gas energy costs include the wholesale cost of purchasing gas from a given location plus the cost of transporting the gas to the gas utility’s distribution system.[69] This indirectly captures gas transmission pipeline capacity costs as well as environmental compliance costs.

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[68] Note that when utility incentives for a DER are included as a utility cost, only the difference between the total measure cost and the utility incentive would appear as a host customer cost. Consider an efficiency measure that has an incremental cost of $1000. If the utility offers a $400 rebate, that would be considered a utility cost and the remaining $600 would be a host customer cost. Thus, under the primary MD-UBCA test, which includes both utility and host customer impacts, the total measure cost of $1000 would be included. However, under the secondary Utility Cost Test, which includes only utility system impacts, only the $400 utility rebate would be included.

[69] Note that Table 6 shows Gas System Energy impacts as “Fuel & Variable O&M” (also termed “Gas Commodity” in this report), “Capacity and Storage,” “Environmental Compliance,” and “Market Price Effects.” Market Price Effects are considered not material and this Subsection 4.3.1 covers the other three impacts.

Recommended Method

The recommendation for estimating gas energy costs is to use the Henry Hub + Basis Approach, where "basis" refers to the cost of transporting gas to the BG&E, Washington Gas and/or other gas distribution systems. Specific steps in developing these estimates are as follows:

1. Estimate future annual Henry Hub prices.
    a. For the first three years into the future, use NYMEX Futures prices.
        i. Use straight (unweighted) averages of monthly futures prices available for each year.
        ii. Use futures prices if forecasting gas costs in nominal dollars; remove inflation effects from futures prices if forecasting gas costs in real dollars.
    b. For years 4 and beyond, escalate the year 3 Henry Hub futures price using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) forecast of annual changes in Henry Hub prices. Use annual percent changes in nominal dollars if developing a nominal dollar forecast; use changes in real dollars if developing a real, inflation-adjusted forecast.
2. Estimate the "basis" adder to Henry Hub based on the average historic difference between Henry Hub prices and gas utility summaries of the costs of gas delivered to their systems.
    a. Use three years of such historic monthly price differences.
    b. Convert both sets of prices (Henry Hub and utility delivered prices) to current dollars to remove inflation effects over the three-year period.
    c. Compute the straight (unweighted) average of the 36 inflation-adjusted monthly price differences.
    d. Escalate the historic average basis differential by the rate of inflation if forecasting costs in nominal dollars.
3. Add the annual forecast Henry Hub price to the annual basis adder.

The resulting stream of forecast future prices should be used for all DER measures that affect gas consumption, regardless of whether their consumption is concentrated in winter months or more even spread throughout the year.

Key Issues

The Work Group considered developing different price forecasts for DERs whose effects were concentrated in winter months (e.g., space heating efficiency or electrification measures), than for those whose consumption is spread more evenly throughout the year (e.g., cooking efficiency or industrial process efficiency measures). Both Henry Hub commodity prices and the Maryland transportation basis adders are typically higher in winter months than in summer or swing seasons. Also, much more gas is consumed by Maryland's residential and business customers in winter months than in other months. However, gas utilities typically purchase significantly more gas than they need to meet customer demand in the summer months, when gas is usually less expensive, and put the excess that is not consumed into storage for use in the winter. For example, while only about 30% of Maryland's residential and business gas consumption occurs in non-winter months (April through October),[70] it is possible that 50% or more of annual gas purchases may be made in those months. BG&E suggested that they typically use the straight average of monthly gas prices when they develop price forecasts for other purposes for this very reason. It seems reasonable to replicate that approach when estimating future avoided gas costs for analyzing the cost-effectiveness of energy efficiency and electrification.

The Work Group also considered using delivered prices to the Maryland Citygate,[71] as provided by US EIA, to estimate the basis differential between Henry Hub and delivered prices to the Maryland gas utility distribution systems. However, those reported delivered prices and basis differentials were quite different from BG&E's actual delivery prices and basis differentials.

The Work Group also considered using the difference between Transco Zone 6 (non-New York) futures prices and Henry Hub futures to estimate basis differentials, because JMEU suggested that was likely the best single proxy for delivered prices. However, Transco futures prices are not publicly available. Also, though Transco Zone 6 (non-New York) may be the best proxy for BG&E gas prices, the Company also gets some of its gas through both Columbia Gas Transmission and Eastern Gas Transmission. The Company's historic delivered prices are not only public but represent the actual blending of prices of the different sources of gas. JMEU also suggested it was problematic that the BG&E prices included pipeline demand charges that it does not believe can be avoided or reduced through EE and/or DR programs. The Consultant Team understands that gas utilities need to plan to meet demand in extreme weather conditions and that some EE and DR programs may not reduce peak demand under those conditions. However, the Consultant Team also suggests that there is good reason to expect building weatherization, gas heating equipment efficiency and other key gas EE measures – as well as full electrification of space heating – to reduce gas demand (relative to what it would have been absent those measures) under extreme weather conditions. Thus, the Consultant Team concludes it is appropriate to indirectly account for reductions in pipeline demand charges in the way energy costs are computed.

The Work Group also considered using more than three years of Henry Hub futures prices, but concerns were raised about whether trading volumes for gas purchased more than three years into the future would be robust enough to provide a reliable estimate of likely future prices.

Timeline for Adoption and Interim Method

Because the recommended method relies on readily available data and forecasts, it can be applied immediately. Indeed, it has already been used by the EmPOWER Work Group.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

The EmPOWER IE, WGL, and OPC support the recommendation. JMEU supports the high-level approach of using Henry Hub Futures plus a "basis" adder, but does not support using historic delivered costs to the BG&E system to estimate the "basis" adder, primarily because

[70] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SMD_m.htm
[71] https://www.eia.gov/dnav/ng/hist/n3050md3M.htm

they include pipeline demand charges the Company does not believe are avoidable (see discussion of key issues above). The Company supports using Transco Zone 6 (non-New York) futures prices instead. It also raised the potential to use delivered costs to its system with pipeline demand charges removed, though that would require some internal analysis which would not be publicly available (unless the Company chose to make it available).

The following table summarizes the UBCA Consultant Team's perspective on the pros and cons of four different approaches to estimating the "basis" adder. The first option is the one recommended in this report. The last option (#4) is JMEU's preferred approach. Option #2 is the same as Option #1, except that the utilities would need to analyze historic delivered costs, to estimate the portion of such costs that are associated with pipeline demand charges and remove them. JMEU has indicated that this could be done. Option #3 is the same as Option #2, except that the removed pipeline demand charges would be presented separately and measures that are determined to have an effect on such charges would be assigned that additional benefit.

Option		Reflects Mix of Pipelines Delivering Gas to MD?	Publicly Available Data?	Impact on EE & Electrification Measures that Do Affect Peak	Impact on EE & Electrification Measures that Don't Affect Peak	Effort Required
1	Utility delivered costs, including demand charges	Yes	Yes	Accurate	Overstates	Very low
2	Utility delivered costs, excluding demand charges	Yes	No, but can made public	Understates	Accurate	Low
3	Utility delivered costs, excluding demand charges - separate estimate of demand impacts	Yes	No, but can made public	Accurate	Accurate	Medium
4	Transco Zone 6, non-NY futures	No	No	Understates	Accurate	Very low

4.3.2. Gas Market Price Effects

Definition

Market price effects are changes in wholesale market prices that result from a change in energy consumption. They are the manifestation of the fundamental "law of supply and demand" – i.e., when demand declines, prices go down (and vice versa).

Recommendation

The recommendation is to consider gas price effects from DERs as not material. Gas commodity prices are a function of regional if not national demand. While changes in Maryland demand for gas as a result of energy efficiency and/or electrification programs should conceptually have some effect on prices, there is no current evidence to suggest such effects would be large enough to be considered material and therefore to warrant quantification. The most recent New England Avoided Energy Supply Cost Study (2024) estimated the 15-year levelized price effect of gas efficiency measures as equal to

$0.009/MMBtu saved for the state of Connecticut.[72] That is less than 0.2% of the same study's estimated avoided gas cost for southern New England.[73]

Note that this recommendation is a proposed change to the UBCA Phase I recommendation.

Extent of Agreement within UBCA Work Group – **Consensus**

JMEU, OPC and EmPOWER IE all support this recommendation and no stakeholder expressed opposition to it, so this is considered a consensus recommendation.

However, the Consultant Team notes that while WGL did not provide direct feedback on this recommendation, the Company has historically supported inclusion of gas market price effects in EmPOWER cost-effectiveness analyses.

4.3.3. Gas Distribution Capacity Costs

Definition

Gas distribution capacity costs are the costs associated with delivering gas from the point at which interstate transmission pipelines connect to the gas utility distribution system to retail customers. They are predominantly the capital costs incurred to ensure that the delivery capacity of pipes and related infrastructure is sufficient to meet the peak demands of customers downstream of each "pipe" or infrastructure element.

There are two scenarios in which the potential value of avoiding or deferring gas distribution capacity costs should be considered in benefit-cost analysis (BCA) of DERs:

1. Non-pipe solutions (NPS) in which energy efficiency, demand response and/or electrification are targeted to specific geographic areas in order to defer/delay or avoid a specific gas distribution system investment; and
2. System-wide DER initiatives in which energy efficiency, demand response and/or electrification programs are offered to all gas customers.

Recommended Method – Non-Pipe Solution (NPS)

For an NPS, the potential economic benefit of avoiding or deferring a specific capital investment in the gas distribution system will need to be a customized estimate based on the specific investment being deferred or avoided. The overarching approach should be to compute the difference between:

A. the net present value (NPV) of the stream of revenue requirements associated with the capital investment in a scenario in which the NPS is not deployed; and
B. the NPV of the stream of revenue requirements associated with the capital investment in a scenario in which the NPS is deployed.

The value of deferring a capital investment is associated with the time value of money, which will be a function of the 2% real discount rate adopted by the Maryland Commission in the

[72] 2024 AESC, Table 115 on p. 255. The value of the price effect varies by state, largely driven by how much gas is consumed in buildings and industry in each state. Connecticut results are presented here because that is the New England state whose total annual gas consumption is closest to Maryland's (Massachusetts is much greater and the other New England states are much lower).
[73] 2024 AESC, Table 5, on p. 10.

UBCA Phase 1 process.[74] The greater the number of years that a capital investment is deferred, the greater the difference in NPVs will be and therefore the greater the economic value of the NPS will be. If an NPS is estimated to be sufficient to completely eliminate or indefinitely avoid the need for a capital investment – rather than just deferring it for a number of years – the value of the avoided capital investment will simply be the NPV of the stream of revenue requirements associated with the capital investment under the no NPS scenario.

Recommended Method – System-Wide DER Initiatives

For system-wide DER initiatives (e.g., gas energy efficiency programs that are available to all of a utilities' customers rather than just those in specific, targeted geographic area), the gas distribution system cost impacts should be estimated using the Ratio of Cost to Load Growth method using the following steps:

1. Identify areas of the gas distribution system where capital investment is required to meet load growth.
2. Estimate peak demand load growth for a period of time into the future for the areas identified in Step 1.[75] The analysis period should be at least five years, though a longer period (e.g., 10 years) would be better if practical.
3. Estimate future capital investments associated with load growth in the areas identified in Step 1 over the time horizon for which peak load growth is analyzed in Step 2.
4. Divide the estimated cost of future load growth-related investments from Step 3 by the estimated peak load growth from Step 2. Estimates should be expressed in terms of $ per peak-hour MCF.
5. Multiply the resulting cost per unit of peak load growth from step 4 by the portion of total annual system peak demand that is associated with the areas identified as experiencing peak load growth in Step 1. For example, if only 20% of the system is experiencing peak load growth, the result from Step 4 would be multiplied by 0.2.
6. Annualize capital costs by multiplying the total cost per unit of peak load growth developed in Step 5 by the utility's real levelized carrying charge over the cost-weighted average life of the growth-related capital investments identified in Step 3.

Key Issues

The Technical Work Group discussed several different issues related to the recommended method for valuing gas distribution system cost impacts of DERs. What follows are the key issues discussed and how they were addressed in the final recommendation:

- **Gas distribution system investments do not necessarily map or track load growth.** Many investments have nothing to do with load growth and others may be only partly driven by load growth. While it is certainly true that many gas distribution system

[74] Real discount rates exclude the effects of inflation. If the streams of revenue requirements are expressed in nominal dollars (i.e., including forecast effects of inflation), then a higher nominal discount rate that includes forecast levels of inflation would be used instead.

[75] Using a forward-looking analysis period is preferable. However, if it is impractical to use such future forecasts, the analysis could instead use actual capital investment and load growth over the past five years as a proxy for the future.

investments have nothing to do with load growth, the recommended method addresses this fact by including only load growth-related capital investments in the calculations.

- **Some gas distribution investments are made for multiple reasons.** This is a legitimate concern. While some gas distribution system investments are clearly not related to load growth and some are clearly driven entirely (or almost entirely) by load growth, there are others for which addressing load growth is just one of several factors driving the investments. In such cases, judgement will be required when determining the capital cost to include Step 3. It could even be reasonable to assign a portion of the capital cost of such a project to load growth – again, based on expert judgment of the importance of load growth as a factor in project.
- **System-wide load growth may be small or even non-existent, especially in the context of state decarbonization policy**. This is a reasonable concern if the method were to be based on *system-wide* capital investment divided by *system-wide* load growth. However, even if there is no system-wide peak demand load growth, there can be load growth in parts of the system (it may just be offset by declining peak demand in other parts of the system). The proposed method addresses this concern by focusing only on areas of the system experiencing peak load growth. The resulting cost per unit of peak demand for those portions of the system is then "diluted" through a weighted average calculation (Step 5) that includes the portions of the system that have zero load growth and therefore zero potential capital cost savings from reducing peak demand.
- **Capacity additions are lumpy and can be a function of decades of load growth, so dividing five years of capital costs by five years of load growth may present an inaccurate assessment of the value of reducing load growth**. It is certainly true that growth-related capital investments planned for a particular five-year period – the value in the numerator of the proposed method – could be the result of decades of load growth rather than just the five years of load growth included in the denominator of the proposed method. However, it is equally true that the load growth included in the denominator will contribute to capital projects that are not included in the numerator because they will occur (or have already occurred) outside the five-year analysis period. Thus, while the recommended approach may be somewhat "lumpy" and potentially overstate costs per unit of peak demand in some cases, it will understate costs in other five-year periods. Over time, this lumpiness should balance out. The lumpiness could be reduced if the analysis period were increased to more than five years (e.g., 10 years).
- **Load growth can be sporadic, both locationally and temporarily, making an average that is computed over five years problematic, suggesting that avoided costs should be estimated only for locationally-specific changes in forecast capital investments**. This concern is related to the concern in the bullet above. The problem is that it is impractical to conduct detailed, customized estimates of changes in forecast capital investments – for every element of the gas distribution system – that may result from system-wide efficiency and/or demand response programs. As a result, this recommendation would effectively mean only accounting for gas distribution system cost reductions from non-pipe solutions and implicitly assuming

that there are no benefits from system-wide programs even if implemented for many years with growing cumulative effects on peak demand.

- **Gas utilities must plan to meet demand under extreme conditions, potentially including winter temperatures experienced only once every 50 years**. This reality can be addressed within the proposed method. For example, the level of load growth included in the Steps 2 and 4, could be extrapolated to what it would be experienced under the once-in-50-years weather (or whatever metric for which the utility must plan), provided that the peak demand savings associated with efficiency, demand response and electrification measures are then also estimated for such extreme weather conditions.
- **The range of capital costs identified as "demand-related" by the Commission when establishing gas tariffs is much broader than those that are just demand-related**. While that may be true, identification of "demand-related" costs for tariff-setting is not necessarily the same thing as identification of costs that gas efficiency, demand response, and/or electrification programs can defer. If gas DERs cannot have any effect on a set of capital costs (e.g., investments required solely for health and safety reasons and/or to replace corroded and/or leaky pipes), those costs should not be included in estimates of the cost-effectiveness of the DERs.
- **EmPOWER programs do not currently estimate gas peak impacts**. The recommendation will require that gas peak impacts be estimated. This can be done in much the same way that electric peak impacts are estimated for different efficiency measures. It may even be reasonable to use existing electric load shapes for key end uses to develop gas peak impacts. For example, load shapes for electric resistance heating could be used to estimate the portion of annual heating energy consumption that occurs during winter peak hours (e.g., 7 to 9 am on the coldest days of the year), adjusted as necessary to reflect the extreme weather conditions for which gas utilities must plan to meet peak demand.

Timeline for Adoption and Interim Method

The recommended method requires both detailed forecasts of capital investments and load growth, as well as estimation of the portion of capital investments that are load growth-related. Because recent forecasts may not be readily available and there is some complexity to the analysis, the recommended method should not be expected to be universally applied until up to a year after it is formally approved. However, it can be utilized sooner than if a gas utility has the ability to do so.

There are no reasonable alternatives to the recommended method. The impact is also not expected to be large relative to other benefits (i.e., gas commodity savings and GHG emission reductions) of gas efficiency and electrification programs. For both of these reasons, the recommended interim method is to assume zero impact.

Extent of Agreement within UBCA Work Group – **Non-Consensus**

There is disagreement on the recommended method for gas distribution cost impacts of system-wide DER programs. OPC and the EmPOWER IE support it. JMEU conceptually supports the system-wide average approach. However, it suggests that the approach is "not applicable under current gas system conditions." Thus, JMEU recommends limiting application of this impact for now to location-specific evaluations, such as for non-pipe solutions, and potentially considering adopting the recommended system-wide method in the future "as conditions evolve."

WGL takes the opposite position. It considers all costs that the Commission identifies as "demand-related" and "commodity-related" for tariff-setting to be marginal in the long-run and therefore suggests that all such costs should be included in calculations of avoidable gas distribution system investments when valuing system-wide DER programs. Such an approach would likely lead to much larger assumed avoided gas distribution costs than the Consultant Team's recommended method.

The Consultant Team believes that while imperfect, the recommended method is the most reasonable option. Assuming system-wide efficiency, demand response and electrification programs will have zero impact on gas distribution costs under the best current estimate of what the future holds is not reasonable. Conversely, it is unreasonable to value such DERs based, in part, based on gas distribution costs that no amount of system-wide DER deployment could ever defer or avoid capital investment.

4.3.4. Gas Transmission and Distribution (T&D) Losses

Definition

Not all of the gas that leaves the wellhead arrives at individual gas utility distribution systems and not all gas that is delivered to the gas distribution system arrives at individual customers' meters. There are leaks – or losses – along the way. Also, small amounts of gas may be burned by the gas utility itself as part of operating the distribution system.

Recommendation

The recommendation is to consider the effects of DERs on gas T&D losses as not material. Gas system losses are largely a function of pressure in pipes. The higher the pressure, the greater the losses. However, gas utilities tend to try to maintain constant, stable pressures in their distribution pipes. Thus, reductions in volumetric flows through pipes that may result from energy efficiency or electrification programs will probably not materially affect losses – i.e., the marginal loss rate from gas DERs is likely very low and therefore likely not worth the effort to quantify.

Note that this recommendation is a proposed change to the UBCA Phase I recommendation.

Extent of Agreement within UBCA Work Group – **Consensus**

JMEU, OPC and EmPOWER IE all agree with the recommendation. No stakeholder expressed any disagreement.

4.3.5. Gas Utility System Risk

Definition

There is uncertainty associated with many aspects of future gas utility system costs. Along with that uncertainty is the risk of adverse (i.e., high cost) outcomes. Uncertainty can be addressed in forecasts of energy and other utility system costs through probability-weighting of a range of potential future scenarios. However, that is uncommon in forecasts used for DER benefit-cost analyses, which typically rely just on a single "best estimate" of what the future will hold. Moreover, because most customers are risk averse, there is inherent value in reducing exposure to the *worst* potential outcomes.

DERs are commonly considered to be risk mitigating for a range of reasons including:

- Reducing exposure to future gas commodity (and transmission) price uncertainty;
- Reducing exposure to the cost of future environmental regulations (if a DER reduces emissions);[76];
- Providing "option value" – i.e., slowing load growth which buys time to recalibrate distribution system needs assessments and allows for the emergence of lower cost solutions;
- Diversifying the resources relied upon to meet customers gas needs; and
- Increasing the modularity and flexibility of utility resources – i.e., when relying on 100 different DERs instead of 1 major traditional distribution system investment, you both reduce exposure to significant cost overruns by "not putting all your eggs in one basket" and by retaining the ability to shift emphasis from lesser performing DERs the better performing DERs.

While there are risks associated with DERs (e.g., performance risk) as well as traditional supply-side alternatives, most experts agree that "net risk" is lower with DERs for the reasons stated above.[77] There is economic value associated with any such net reduction in risk.

Recommended Method

The Consultant Team recommends use of the following "adders" as defaults for valuing risk impacts of DERs:

- 10% of all gas system cost reductions resulting from energy efficiency and electrification initiatives, with no adder for gas demand response initiatives.

Though the proposed energy efficiency adder is the same in percentage terms as the proposed adder for the risk mitigation benefits of energy efficiency on electric system costs, it will be significantly lower in absolute dollars to the extent that gas avoided costs remain lower than electric avoided costs. No adder is proposed for gas demand response given the uncertainty over the extent to which it is likely to be able to affect demand under extreme weather conditions.

As an alternative to the efficiency adder, utilities can exercise the option to quantify risk through scenario analyses or other studies, provided that such analyses or studies address multiple ways in which DERs materially affect risk, assign probabilities to different possible outcomes, and assign value (beyond just probability-weighting) to the benefit of avoiding the worst cost outcomes.

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[76] Such potential future environment compliance costs would not be embedded in current energy or capacity price forecasts.
[77] See Table 6-2 in National Association of State Energy Officials (NASEO), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, 2026 (https://naseo.org/Data/Sites/1/media/tknaseo/nspm-main-2026-final.pdf).

Key Issues

See discussion of electric system risk in Subsection 4.2.7 above. Note that while there is even less empirical data on the magnitude of the risk mitigating benefits of DERs on gas costs, there is reason to believe that proposed adders are reasonable. For example, gas commodity costs have historically fluctuated substantially more than electric energy costs so there may be greater value (in percentage terms) to reducing exposure to gas price volatility than to electric price volatility.

Timeline for Adoption and Interim Method

Because of its simplicity, this recommendation can be adopted immediately.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus on this recommendation with both EmPOWER IE and JMEU indicating support in response to its inclusion in the first draft report and no stakeholder opposing it.

4.3.6. Gas System Reliability and Resilience

Definition

As with the electric utility system (see subsection 4.2.9 above), gas utility system reliability is the ability to maintain gas delivery to customers in the face of routine uncertainty in operating conditions. As is also the case with electric utility systems (see subsection 4.2.10 above), gas utility system resilience is the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from unusual (not routine) disruptions such as extreme storms, cyber security attacks, etc..

Recommended Method

The recommendation is to consider the effects of DERs on gas reliability and resilience as not material for now. Unlike electric utilities, gas utilities plan capital investments in the distribution system to meet truly extreme weather conditions (e.g., conditions that may be experienced only once every 50 years). In that context, it is unlikely that there are material opportunities for improving reliability and resilience beyond what would already be captured in avoided distribution system capacity costs. The Consultant Team is also unaware of any documented examples of such impacts being monetized in the industry. This conclusion could be revisited in the future if more or better information becomes available.

Note that this recommendation is a proposed change to the UBCA Phase I recommendation.

Extent of Agreement within UBCA Work Group – **Consensus**

EmPOWER IE and JMEU both support the proposal; no stakeholder expressed any objection.

4.3.7. Credit and Collection Costs

Definition

As with electric utilities, gas credit and collection costs are utility costs associated with customer bill payment challenges. These costs can take several forms including the carrying costs of arrearages, costs of engaging customers who are in arrears, costs of disconnections and reconnections, costs of writing off bad debt and costs associated with bill payment subsidies or discounts. These costs are all ultimately paid by other utility customers.

To the extent that DERs installed by customers can lower their bills, they can improve the ability of customers to pay their bills and therefore reduce utility credit and collection costs. While this conceptually applies to all customers, it is typically considered most significant for DERs targeted to low-income households.

Recommended Method

As recommended for electric utilities (see Section 4.2.10 above), the primary recommendation for valuing this gas utility impact is to apply a 2% multiplier to annual bill savings for low-income customers who receive bill savings of at least $100 per year from DERs installed in their homes. Estimates of annual bill savings would be based on current retail rates and the magnitude of changes in annual energy consumption for the average low-income participant in a particular DER program. For electrification initiatives, the 2% multiplier should be applied to impacts on total energy bills – i.e., the net impact of increasing electric bills and decreasing fossil fuel bills. The annual effect of the 2% multiplier over the life of the DER savings should be converted to a present value (PV) benefit (or cost, if electrification increases total energy costs) using the UBCA approved 2% real discount rate.

For example, if a low-income home weatherization (efficiency) program is projected to save 100 therms per year for 25 years on average for each low-income participant in the program, in a utility system with an average residential retail cost per therm of $1.50, the estimated annual bill savings would be $150 (100 therms * $1.50/therm = $150) and the credit and collection cost savings benefit per participant would be computed as follows:

Annual credit and collection cost savings: 100 therms * $1.50 * 2% = $3

PV of credit and collection cost savings (Excel formula): PV(2%,25 years,$3) = $59

This recommendation is consistent with current EmPOWER practice. As the following table shows, it is also conservative relative to studies that have been conducted regarding the impacts of low-income weatherization (efficiency) programs.

The low-income bill savings multiplier could be revised in the future based on new research or analysis. New research and analysis could also potentially be used to develop multipliers or other mechanisms for assigning economic value to impacts of DERs on credit and collection costs of non-low-income customers.

Key Issues

See discussion of electric credit and collection costs in Section 4.2.10 above.

Timeline for Adoption and Interim Method

The proposed 2% bill savings multiplier involves fairly simply assumptions and calculations and is therefore recommended to be implemented immediately.

Extent of Agreement within UBCA Work Group – **Consensus**

EmPOWER IE, JMEU and OPC support the proposal.

Both parties who commented on the implementation timeline (JMEU and EmPOWER IE) supported the proposed timeline.

4.3.8. Direct Utility Costs to Promote DERs

Definition

Direct utility costs to promote DERs include any rebates or other financial incentives,[78] utility direct investments, utility marketing costs to promote DERs, utility costs of managing and evaluating DER initiatives and any applicable utility performance incentives.

Recommended Method

All direct utility costs to promote DERs should be estimated for forward-looking benefit-cost analyses (BCAs); for retrospective BCAs, actual utility direct costs should be included.

Key Issues

Treatment of utility direct costs of promoting DERs in BCAs is straightforward and therefore was not discussed within the TMS. Stakeholders provided feedback via comments on draft versions of this report.

Timeline for Adoption and Interim Method

All utility direct costs of promoting DERs should be estimated and immediately included in BCAs of DERs.

Extent of Agreement within UBCA Work Group – **Likely Consensus**

There is likely consensus on recommendations for this issue; no specific comment was provided by any stakeholder in review of this report, but no stakeholder objected or expressed reservations to this item being characterized as “consensus.”

4.4. OTHER FUEL IMPACTS

Definition

“Other fuels” refers to fuels other than those that are the primary focus of a utility program. This includes those not supplied by regulated electric and gas utilities. They include fuels used in buildings and industrial applications, such as fuel oil and propane, as well as fuels used in transportation, such as gasoline and diesel. For a gas utility running a program, “other fuels” can include impacts associated with the electric system, depending on the program. For an electric utility running a program, “other fuels” can include impacts associated with the gas system (Table 7 in Section 3.3 covers this with “other utility system impacts”).

Multiple DERs can affect consumption of other fuels. Examples can include:

[78] Note that when utility incentives for a DER are included as a utility cost, only the difference between the total measure cost and the utility incentive would appear as a host customer cost. Consider an efficiency measure that has an incremental cost of $1000. If the utility offers a $400 rebate, that would be considered a utility cost and the remaining $600 would be a host customer cost. Thus, under the primary UBCA test, which includes both utility and host customer impacts, the total measure cost of $1000 would be included. However, under the secondary Utility Cost Test, which includes only utility system impacts, only the $400 utility rebate would be included.

- Efficiency measures such as attic insulation can not only reduce electric cooling energy consumption but also fuel oil or propane consumption for space heating;
- Increased use of diesel or other fuels in fossil fuel-fired distributed generation;
- Increased use of diesel or other fuels by industrial customers who deploy on-site generation when they participate in demand response events;
- Electrification of homes or businesses using fuel oil or propane for space heating, water heating, cooking, drying, industrial processes or other end uses; and
- Electrification of vehicles

Conceptually, impacts of DER investments on fuel oil, propane, gasoline, diesel and other unregulated fuel costs should include the effect of DER-driven changes in Maryland demand on market prices Maryland consumers pay for such fuels. However, petroleum prices are largely a function of global demand. Thus, for the purposes of the MD-UBCA, the recommendation is to assume that price effects are "not material" because small changes in consumption just in the state of Maryland are not expected to have a measurable effect on global prices. Note that this is a proposed change to the UBCA Phase I MD-UBCA Test (which included market price effects for Other Fuels as material for some DERs).

Recommendation

Impacts of DERs on other fuel costs should be estimated in the following two-step process:

1. Estimate average prices for the current year
    a. For fuel oil, propane, kerosene and other fuels used in buildings, the recommendation is to compute current average prices as the average of the weekly prices during the most recent months of November, December, January, February and March as reported by the U.S. Energy Information Administration for the state of Maryland.[79]
    b. For gasoline, diesel and other transportation fuels, the recommendation is to compute current average prices as the average of weekly prices during the most recent 12-month period as reported by the U.S. Energy Information Administration for the Central Atlantic (PADD1B) region.[80] To the extent such prices include state taxes, such taxes should be removed.
2. Escalate current average prices into future years using the year-over-year change in costs included in the most recent U.S. Energy Information Administration Annual Energy Outlook reference case forecast for each fuel for the Mid-Atlantic region.[81]

Key issues

The primary focus of discussion on this method was the best reference for transportation fuels, both for current prices and forecast future prices. The Consultant Team originally proposed referencing AAA reported prices for Maryland. The JMEU suggested considering New York Harbor RBOB gasoline and ULSD diesel futures be considered, both because AAA doesn't report historic prices in in detail (and picking one particular weekly value is problematic given the potentially significant changes the market can experience week to

[79] https://www.eia.gov/petroleum/heatingoilpropane/
[80] https://www.eia.gov/petroleum/gasdiesel/
[81] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&cases=ref2025&sourcekey=0

week) and New York Harbor "is the closest major trading hub for refined products used in Maryland. However, New York Harbor prices appear to be considerably lower than actual Maryland pump prices – e.g., about $2.00 in late Feb 2026 compared to AAA reported pump prices of about $3.00 for same time. This may be partly because of state taxes (which should be removed as noted above) and partly because they don't account for costs of delivery, which would lead to understating actual costs. In the meeting during which this issue was discussed, BG&E proposed the EIA reference that has been included in the recommendation above.

Timeline for Adoption and Interim Method

The information required to apply the recommended method is readily available, so the recommendation can be adopted and applied immediately.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus on the proposal with the JMEU and EmPOWER IE supporting it and no stakeholder opposing it.

4.5. HOST CUSTOMER IMPACTS

Definition

Host customer impacts refer to impacts beyond those associated with energy bill changes that are experienced by customers who receive DERs. Table 15, excerpted from the Maryland UBCA Phase 1 report, is provided below.

Host customer non-energy impacts (NEIs) can vary significantly by DER type (energy efficiency vs. demand response vs. distributed generation vs. storage), as well as by application, program and measure for a given DER. For example, host customer NEIs from weatherizing a home (often including improved comfort, indoor air quality and/or building durability) are both very different and likely much more substantial than the NEIs (if any) associated with installing a more efficient refrigerator.

Host customer impacts can be both positive (benefits) and negative (costs). For example, most DER program participants are expected to bear some of the capital cost of DER measures. The vast majority of other host customer impacts from efficiency measures are benefits, but there are some that are not. The balance of other non-measure impacts for other DERs is less clear. That is because, while there is a long history of analysis and quantification of non-energy impacts from efficiency measures, less industry research has been conducted to assess non-energy impacts of other DERs.

Table 15: Examples of Host Customer Non-Energy Bill Impacts

Impact	Description and Examples
Energy Impacts	
DER Measure Costs	The portion of DER measure costs born by the host customer (e.g., cost net of utility incentives)
Transaction Costs	Non-financial costs to install DERs (e.g., application fees, time spent facilitating installation, paperwork)
Interconnection Fees	Costs paid by customers to interconnect DERs to the electric grid
Risk	Uncertainty regarding price volatility, power quality and performance of DER equipment
Resilience	Ability to adapt to changing conditions and withstand, respond or recover from disruptions
Tax Incentives	Government tax incentives (or other incentives) that defray the cost of DERs
Non-Energy Impacts	
Asset Value	Changes in the value of a home or business as a result of the DER (e.g., increased building value)
Water cost impacts	Costs or cost savings from increased or decreased water consumption resulting from DER installation
O&M costs	Changes in operation and maintenance costs
Productivity	Other changes in productivity (e.g., reduced business waste streams, increased worker productivity)
Economic well-being	Economic impacts beyond bill savings (e.g., reduced service terminations, reduced foreclosures)
Comfort	Changes in comfort (e.g., thermal, noise and lighting quality)
Amenity	Changes in other values (e.g., less refrigeration capacity, more “free time”, performance uncertainty)
Health & Safety	Changes in air quality or other factors affecting medical costs, availability for work/school, deaths, etc.
Empowerment	Satisfaction from ability to control energy consumption and bills
Pride	Satisfaction from contributing to social good (e.g., from reduced environmental footprint)

Recommended Method

Given the diversity of host customer impacts and the lack of empirical data on NEIs for DERs other than energy efficiency, the recommended method for quantifying such impacts has some process elements as well as specific quantification elements:

1. Identify impacts likely to be material for each DER, using research as needed;
2. Routinely quantify all of the following (for all DERs) through research and analysis:
    a. DER measure costs born by host customers (i.e., net of utility incentives)
    b. Tax credits and/or other government subsidies available for installed DERs (if any)
    c. Water cost changes (if any)
    d. Operation and maintenance (O&M) cost changes
3. Use a combination of research/analysis and proxy adders for other impacts identified as material in Step 1.

a. Default: develop a single adder for impacts that are both *material* (per Step 1) and *not otherwise monetized* (per Step 2 and/or Step 3b). Such adders should be developed separately for each DER. Adders could be expressed as a percent of all utility system impacts, as a percent of a subset of utility system impacts, or in some other form.
b. Optional: conduct secondary and/or primary research and/or analysis to inform estimates of the economic value of specific, select host customer NEIs. Once completed, such research/analysis can be used to modify the default adder in Step 3a (i.e., as the default adder covers a smaller list of material impacts for which specific economic values have not been developed).

Key Issues

- **Lack of information on non-energy impacts (NEIs)**. One of the challenges of developing estimates of host customer impacts is that there has been relatively little research, analysis and quantification of some host customer NEIs. There has been considerable analysis, across many states and for more than 20 years, of host customer NEIs for energy efficiency. Indeed, the current EmPOWER BCA assumptions rely on that research to quantify a range of such impacts. On the other hand, there has been relatively little research and analysis of host customer NEIs for other DERs. That is why the first step in the recommended method is for Maryland utilities, stakeholders and work groups established to address initiatives for different DERs to first attempt to systematically identify host customer NEIs that are applicable to and likely material for each type of DER. That initial assessment should rely on any already available information and potentially include some additional secondary research. It will also inevitably require some qualitative assessment. However, that initial step will be necessary to inform decisions in Step 3a to develop default adders as well as potential areas to target additional research and analysis in Step 3b.
- **Materiality of different host customer NEIs**. Utilities raised questions during the Technical Subgroup Meetings regarding whether some of the potential host customer NEIs could be considered insufficiently "material" to merit addressing. The issue of materiality is an important one and, as discussed above, initiating a discussion of host customer NEIs for each type of DER to assess materiality, even if only qualitatively, is a fundamental step in the recommended method. That recommendation reflects the reality that the UBCA Phase 2 process, which needed to address dozens of different DER impacts (of which host customer impacts are just one), was not the right venue for establishing materiality. Further, as also noted above, the applicability and materiality of different kinds of host customer NEIs will likely vary considerably from one DER type to another. Thus, it would be problematic to generalize about the materiality of certain subcategories of host customer impacts.
- **Lack of precision associated with adders**. By definition, adders are somewhat crude tools in that they establish a certain multiplier or value that generically gets applied to all applications of a given DER. One alternative is to only include a host customer impact if it has been specifically studied, quantified and monetized. While such direct monetization (assuming it is done well) is always preferable to an generic adder, limiting the inclusion of non-energy impacts to those that have been studied and directly monetized will essentially mean treating some impacts as zero (at least until

they are studied, which may take a while given other priorities), even if there are qualitative reasons or even some (non-monetary) quantitative data to suggest that they provide economic value that is materially greater than zero. That can bias BCA results that include host customer impacts against the DER because the primary host customer cost of DERs – the customer's contribution to buying the measure – will always be quantified and included.

Timeline for Adoption and Interim Method

The information required to complete Steps 1 and 2 of the recommended method should be relatively easy to acquire, so those steps should be undertaken immediately. However, the recommendation in Step 3a of the proposed method – to develop adders for host customer impacts that are not addressed in Step 2 and for which existing studies per Step 3b – requires a deliberative process and likely some research, at least for DERs other than energy efficiency. Thus, Step 3a likely cannot be completed until 6-12 months after Commission approval of the recommended method (if it is approved). Since it is only a relatively near-term issue, the interim recommendation would be to assume zero additional host customer impacts.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus on this recommendation with OPC, JMEU and the EmPOWER IE all supporting the proposed method and no stakeholder opposing it.

4.6. SOCIETAL IMPACTS

4.6.1. Societal Greenhouse Gas (GHG) Impacts

Definition

GHG impacts are the value of changes in emissions of carbon dioxide, methane and other greenhouse gases as a result of increased deployment of DERs.

Recommendation

Impacts of DERs on GHG emissions should be estimated through the following two-step process:

1. Multiply changes in electric kWh, gas therms, and other fuel impacts of DERs by fuel-specific, long-run marginal emission rates (LRMER). LRMERs should be estimate in the following manner:
    a. Electricity: use annual outputs from Power System Modeling (discussed in electric energy and capacity costs subsection above)
    b. Gas and Other Fossil Fuels: use the U.S. Environmental Protection Agency's (EPA's) January 15, 2025 Report "Emission Factors for GHG Inventories".
2. Multiply the estimated change in emissions from Step 1 by the Social Cost of Carbon (and cost of other GHGs) as estimated from the U.S. EPA's report on global damage costs of GHG emissions using a 2% real discount rate. A copy of the applicable table

from that report is provided below in Table 16.[82] Values for years in between 2020, 2030, 2040, etc. should be interpolated. Also, because the values provided by EPA are in 2020 dollars, inflationary effects will need to be added to present them in whatever year's dollars future benefit-cost analyses use.

Table 16. Estimates of the Social Cost of Greenhouse Gases (SC-GHG), 2020-2080 (2020 $)

SC-GHG and Near-term Ramsey Discount Rate									
	SC-CO_2 (2020 dollars per metric ton of CO_2)			SC-CH_4 (2020 dollars per metric ton of CH_4)			SC-N_2O (2020 dollars per metric ton of N_2O)		
Emission Year	Near-term rate			Near-term rate			Near-term rate		
	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2020	120	190	340	1,300	1,600	2,300	35,000	54,000	87,000
2030	140	230	380	1,900	2,400	3,200	45,000	66,000	100,000
2040	170	270	430	2,700	3,300	4,200	55,000	79,000	120,000
2050	200	310	480	3,500	4,200	5,300	66,000	93,000	140,000
2060	230	350	530	4,300	5,100	6,300	76,000	110,000	150,000
2070	260	380	570	5,000	5,900	7,200	85,000	120,000	170,000
2080	280	410	600	5,800	6,800	8,200	95,000	130,000	180,000

Values of SC-CO_2, SC-CH_4, and SC-N_20 are rounded to two significant figures.

Key issues

One important issue associated with the recommended method is that the 2023 EPA estimates of the social cost of carbon have been dramatically reduced by the current federal administration. The Technical Methods Subgroup ultimately concluded that the 2023 estimates are most likely to be reflective of the actual damages caused by GHG emissions, particularly given the Commission's approval of the use of a 2% societal discount rate in UBCA Phase 1. Also, the EmPOWER programs have been using the 2023 estimated costs of carbon, so this decision would cement the status quo in Maryland.

The primary focus of discussion on this method was on concerns regarding the use of Power System Modeling (PSM) to develop long-run marginal emission rates for the grid. While there was consensus of the use of LRMERs and as well as agreement that PSM could have advantages over other methods of estimating impacts, as discussed above, utilities have conditioned their support for the PSM approach on the ability of all parties to have input into the development of and review of the draft output from such modeling.

Timeline for Adoption and Interim Method

For electric system impacts, it will likely be a couple of years before Power System Modeling results on long-run marginal GHG emission rates will be available. Thus, an interim strategy is required. The recommended interim strategy is to use either values from the National Laboratory of the Rockies (NLR) Cambium model or assumptions developed by the

[82] U.S. EPA, Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance, and Modified Sources and Emission Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review", EPA report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, November 2023 (https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf).

EmPOWER IE. For DERs other than energy efficiency, the NLR Cambium assumptions on LRMERs may be more reflective of likely actual impacts of DER deployment because the Maryland Department of Environment's forecast may be optimistic about how state policy objectives will ultimately actually affect the grid.

For natural gas and other fossil fuels, the recommended method for estimating emission rates can be adopted and applied immediately.

For both grid emissions and fossil fuels, the recommendation to use the 2023 EPA social cost of carbon to translate emission impacts into dollar impacts can be adopted and applied immediately.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

JMEU, EmPOWER IE and OPC all generally support the proposed method, with the same caveats regarding the importance of utility and other stakeholder input to the Power System Modeling process described in the discussion of electric energy and capacity costs above. No stakeholder opposed the recommendation. This recommendation is marked as "partial agreement" due to the proposed method's incorporation of PSM (which is itself a recommendation with "partial agreement;" see Subsection 4.2.1).

Both parties who commented on the timeline and interim method – the JMEU and the EmPOWER IE – are supportive of those recommendations.

4.6.2. Societal – Other Environmental / Public Health Impacts

Definition

Conceptually, other environmental impacts can encompass a wide range of potential impacts associated with air emissions other than GHGs, water pollution and land use associated with energy generation and consumption. There can be public health impacts associated with all such environmental impacts. However, the primary non-GHG impacts most commonly associated with energy generation and consumption are changes in emissions of criteria pollutants – ozone, particulate matter, carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO2) and lead – as well as volatile organic compounds (VOCs) which create ozone when combined with nitrogen oxides. These pollutants are also well known for significant adverse public health impacts. Thus, they are the primary "other environmental and public health" focus of the Maryland UBCA.

Recommendation

There are several steps to monetizing the impact of DERs on criteria pollutant emissions:

a. Estimating the change in kWh produced by the electric grid and/or BTUs of fossil fuels consumed.
b. Quantifying the air emissions impact of the changes in energy consumption from step "a"
c. Estimating the change in air quality resulting from the change in emissions from step "b"
d. Quantifying the public health impact of changes in air quality from step "c"
e. Estimating the dollar value of the public health changes from step "d"

The focus of the UBCA method recommendation is on steps “b” through “e”. Step “a” is a function of DER energy impact evaluation rather and needs to be developed through DER-specific protocols. For example, the question of how many kWh an efficient air conditioner, how many therms of gas insulating and attic will save, how many gallons of gasoline a program to promote EVs will save (and by how much it will increase kWh consumption) should be addressed through separate analyses and evaluations, just as they have always been.

The recommended method is as follows:

1. Multiply changes in electric kWh, gas therms, and other fuel impacts of DERs by fuel-specific, long-run marginal emission rates (LRMER). LRMERs should be estimate in the following manner:
    a. Electricity: use annual outputs from Power System Modeling (discussed in electric energy and capacity costs section above)
    b. Gas and Other Fossil Fuels: use the U.S. Environmental Protection Agency’s (EPA’s) AP-42[83] or other reputable reference(s) for emission factors.
2. Translate the changes in emissions from Step 1 to dollar values using the EPA’s Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). This tool addresses steps “c”, “d” and “e” above in one analytical engine – estimating changes in air quality, quantifying public health impacts and estimating the dollar value of those public health damages (or damages avoided).

Any additional impacts – beyond those associated with changes in emissions of criteria pollutants and/or their precursor pollutants – could be considered on a custom basis if they are determined to be material and important enough.

Key Issues

- **Power System Modeling vs. EPA’s AVoided Emissions and geneRatio Tool (AVERT) or other methods for estimating emission impacts**. Among the potential alternatives to using Power System Modeling to estimate DER impacts on criteria pollutant emissions from the electric grid is EPA’s AVERT tool. However, AVERT only estimates short-run marginal emission rates – i.e., changes in dispatch of power generators assuming that the mix of generation on the grid is not affected by DERs. Analysis of DER programs should be based on long-run marginal impacts that include both changes in the composition of generation on the grid and which generators are dispatched. Power System Modeling does this. While NLR’s Cambium model produces estimates of long-run marginal emission rates for GHGs, it does not provide such outputs for criteria pollutants.
- **Challenges if EPA’s COBRA tool becomes unavailable**. One potential challenge to the recommended method is its reliance on EPA’s COBRA tool to translate changes in emissions to dollar values associated with changes in public health. This concern potentially applies to a range of other references recommended in this report – as well as potential alternative references. In this case, it is possible to download the COBRA

83 https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors-stationary-sources

tool to maintain its availability, though it may lose some value over time from not being updated or maintained. Ultimately, the methods recommended in this report may need to be refined or changed as a result of new information becoming available, current references changing or becoming unavailable or other factors.

Timeline for Adoption and Interim Method

For electric system impacts, it will likely be a couple of years before Power System Modeling results on long-run marginal GHG emission rates will be available. Thus, an interim strategy is required. The recommended interim strategy is to use either values that could be derived from NLR's Cambium model's estimates of long-run marginal emission rates (LMRERs) for GHGs or assumptions developed by the EmPOWER IE. NLR Cambium does not estimate LRMERs for criteria pollutants. However, assumptions regarding relationships between LRMERs for GHG and LRMERs for criteria pollutants could be developed (e.g., weighting typical criteria pollutant emission rates for gas generation with zero emissions from renewable generation). For example, if gas has an average CO2e emission rate of 500 kg/MWh and the system-wide LRMER for GHGs was 300 kg/MWh, that would be equivalent of 60% gas and 40% renewables on the margin in the long run. One could then estimate average emission criteria pollutant emission rates for gas generators most likely to be on the margin and multiply those rates by 60% (since there would be no emissions from renewables) to generate system-wide LRMERs for each criteria pollutant. This approach may make the most sense if the NLR Cambium model outputs are used as the interim strategy to estimate GHG LRMERs.

For natural gas and other fossil fuels, the recommended method for estimating emission rates can be adopted and applied immediately.

For both grid emissions and fossil fuels, the recommendation to use the EPA's COBRA tool to translate emission impacts into dollar impacts can be adopted and applied immediately.

Extent of Agreement within UBCA Work Group – **Partial Agreement**

JMEU, EmPOWER IE and OPC all generally support the proposed method, with the same caveats regarding the importance of utility and other stakeholder input to the Power System Modeling process described in the discussion of electric energy and capacity costs above. No stakeholder opposed the recommendation. This recommendation is marked as "partial agreement" due to the proposed method's incorporation of PSM (which is itself a recommendation with "partial agreement;" see Subsection 4.2.1).

Both parties who commented on the timeline and interim method – JMEU and the EmPOWER IE – are supportive of those recommendations.

4.6.3. Societal – Resilience Impacts

Definition

Resilience is defined in this report as the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Societal resilience impacts are the benefits to local communities associated with the ability of institutions that provide critical services – such as hospitals, policy stations, and fire stations –

to remain functioning and/or to recover from and begin functioning again quickly after major disruptive events.

Recommended Method

1. Establish a separate Commission process (within the UBCA Work Group or otherwise) to identify an appropriate framework, key metrics, and methodological options and effort level for monetizing societal resilience impacts.
2. In the interim, utilities may use qualitative information to the extent available (e.g., case studies of critical facility benefits from DER investments during major outage events that exceed reliability benefits.)

Key Issues

Existing frameworks for defining and valuing societal resilience are varied, with no standard method and limited experience focused on critical facilities. Both the Consultant Team research and utility and OPC comments indicate that, while societal resilience is an important benefit, there is no widely accepted and analytically rigorous method for determining such values.

The recommended method reflects an understanding that qualitative description of facility benefits is the most reasonable near-term approach given existing capabilities and resources. Given the high level of interest in assessing societal resilience benefits, the Consultant Team recommends that in the long-term, Maryland should pursue a rigorous state-level assessment to determine an approach to these benefits.

Timeline for Adoption and Interim Method

Qualitative explanations of societal resilience benefits can be shared to the extent available immediately. Those that are project-specific will depend on those project timelines. The timeline for a separate Commission process to support monetization of such impacts is to be determined, as discussed in Chapter 6.

Extent of Agreement within UBCA Work Group – **Consensus**

There is consensus on the recommended approach, with the two stakeholders who expressed opinions on it – EmPOWER IE and JMEU – supporting it and no stakeholder opposing it.

5. COORDINATION WITH OTHER WORK GROUPS

This chapter reviews the applicability of the MD-UBCA Test and the associated methods and implementation timelines recommended in Chapter 4 to the Other WGs and the specific DERs and use cases that are pertinent to the Other WGs' respective scope, efforts and underlying regulatory requirements.

5.1. EMPOWER EVALUATION ADVISORY GROUP

Current Cost-effectiveness Requirements

The current EmPOWER BCA test used to evaluate the EmPOWER programs is based on the approved BCA test described in the Future Programming Work Group Report (April 15, 2022, Case No. 9648). The specific impacts in the current test, as compared to the MD-UBCA Test, are presented in Tables 4 – 7 in Chapter 3.

Relevance of MD-UBCA Test and Recommended Methods

The MD-UBCA Test and recommended methods in this report apply to the EmPOWER programs and associated DERs (energy efficiency, demand response, building electrification), to the extent the MD-UBCA Test impacts are relevant and material to EmPOWER related DERs (as shown in Chapter 4, Tables 9 – 11).

However, as noted in Chapter 4.1, the EmPOWER EAG interprets statute as requiring the avoided energy and capacity costs, and associated emission impacts of the EmPOWER programs to be based on the MDE's forecast of how the state's energy production and consumption will achieve its decarbonization goals, regardless of that forecast's ultimate likelihood or accuracy. The Consultant Team notes that if EmPOWER continues to use the MDE forecast, then the adoption of the 'long-term' energy and capacity (and related) impact methods recommended in this report – specifically using a power system modeling (PSM) approach – would be different for EmPOWER BCAs relative to the other Work Group BCAs, which is not optimal, and presents a case of trade-offs for the state (where the PSM is considered by the Consultant Team to be more accurate than the current EmPOWER approach).

Relevant Filing Schedules and Methods Implementation

The EmPOWER 2027-2029 Plan that is due to be filed with the Commission in fall of 2026 is anticipated to reflect the 'immediate' MD-UBCA Test methods presented in Chapter 4, per feedback from the EmPOWER IE (and in consultation with the EAG) as discussed during the TMS process described in Chapter 3. The Consultant Team recommends that as interim and long-term MD-UBCA Test methods (or resulting input values) relevant to EmPOWER related DERs are developed during the 2027-2029 EmPOWER plan period, these changes, to the extent they are material, should be incorporated into any filed updates to the current plan, as directed by the Commission.

5.2. PC44-ELECTRIC VEHICLES

Cost-effectiveness Requirements

The PC44-EV WG informed the development of the EV BCA Method Joint Utility Report (December 2021), which set forth a BCA test that applied NSPM guidance (as presented in Table 4-7 in Chapter 3). Subsequently, in the PC44-EV WG BCA Report (June 2024) and status update in October 2024, the PC44-EV WG recommended that further modifications to EV-specific cost-effectiveness testing should be deferred until the Commission provided definitive guidance on the UBCA docket to ensure that EV methods do not conflict with the overarching unified standards intended for all DERs.

Relevance of MD-UBCA Test and Recommended Methods

The MD-UBCA Test and recommended methods in this report apply to the PC44-EV managed charging programs and pricing strategies, to the extent the MD-UBCA Test impacts are relevant and material to EVs (as shown in Chapter 4, Tables 9 – 11).[84]

For some impact areas, in particular with regard to identifying priority related non-energy impacts (NEIs) to monetize, this will require consideration of trade-offs on methods to select (e.g., from use of a simple proxy adder to more costly in-depth research/study) given the current funding levels of the utility pilot programs vis a vis other DER related investment. The specific priority NEIs and associated methods were only generally discussed in the TMS meetings, with recommendations made in Chapter 4.5 (Host Customer Impacts), and further discussed in Chapter 6, on the process for identifying the priority NEIs to study for DER type, including how such a process and procedures might be undertaken going forward.

Relevant Filing Schedules and Methods Implementation

The filing schedule for Phase II EV Programs is highlighted in Order No. 92166 (January 29, 2026), which aligns the duration of all utility programs to a five-year term to facilitate consistency across EV Pilot programs and simplify evaluation and reporting. Per the Commission's directive and the Joint Utility 60-Day Compliance Filing (March 30, 2026), the current schedule for evaluation, measurement, and verification is as follows:

- **60-day directive (completed March 2026):** Utilities submitted a joint framework describing data and metrics to compare the costs and benefits of utility-side versus customer-side "make ready" investments.
- **180-day directive (July 2026):** Utilities must file comprehensive EM&V plans and cost estimates after Consultant with the PC44-EV WG. These plans will likely integrate third-party evaluations and net-to-gross analyses.
- **12-month directive (January 2027):** Utilities without existing five-year programs must file formal proposals to extend their programs to the full five-year duration.
- **Ongoing reporting:** utilities continue to file semi-annual reports following the Phase I frequency while collaborating with the PC44-EV WG to finalize new metrics that align with MD-UBCA Test methods.

[84] The Consultant Team presented to the PC44 EV Work Group on 8/21/25, which included review and comparison of UBCA Test to current PC44 EV BCA practices. See Appendix A, starting on pg 13.

It is recommended, based on guidance from the PC44-EV WG Leader, that the utility filings reflect the recommended 'immediate' methods identified in Table 9 through Table 11, within 3 to 6 months of the Commission accepting or modifying the recommendations within this report, and to update the methods in the interim and long-term as they become available, with reporting on these updates to the Commission in the utility semi-annual report. This recommendation does not apply to past BCAs that have already been filed with the Commission.

5.3. MESP GRID SERVICES TARIFF AND INCENTIVE DESIGN STUDY

Cost-effectiveness Requirements

Per Maryland Public Utilities Article § 7-216.1, the Commission established energy storage goals, including a requirement for the MESP WG to undertake an Energy Storage Program Design Study to evaluate cost-effective energy storage incentive programs and grid-service tariff methods.

The specific BCA requirements set forth in the Commission's RFP for a consultant Order 91750 with regard to the Energy Storage Program Design Study, as summarized by the MESP Commission Advisor WG lead at an MESP meeting on July 14, 2026, are as follows:

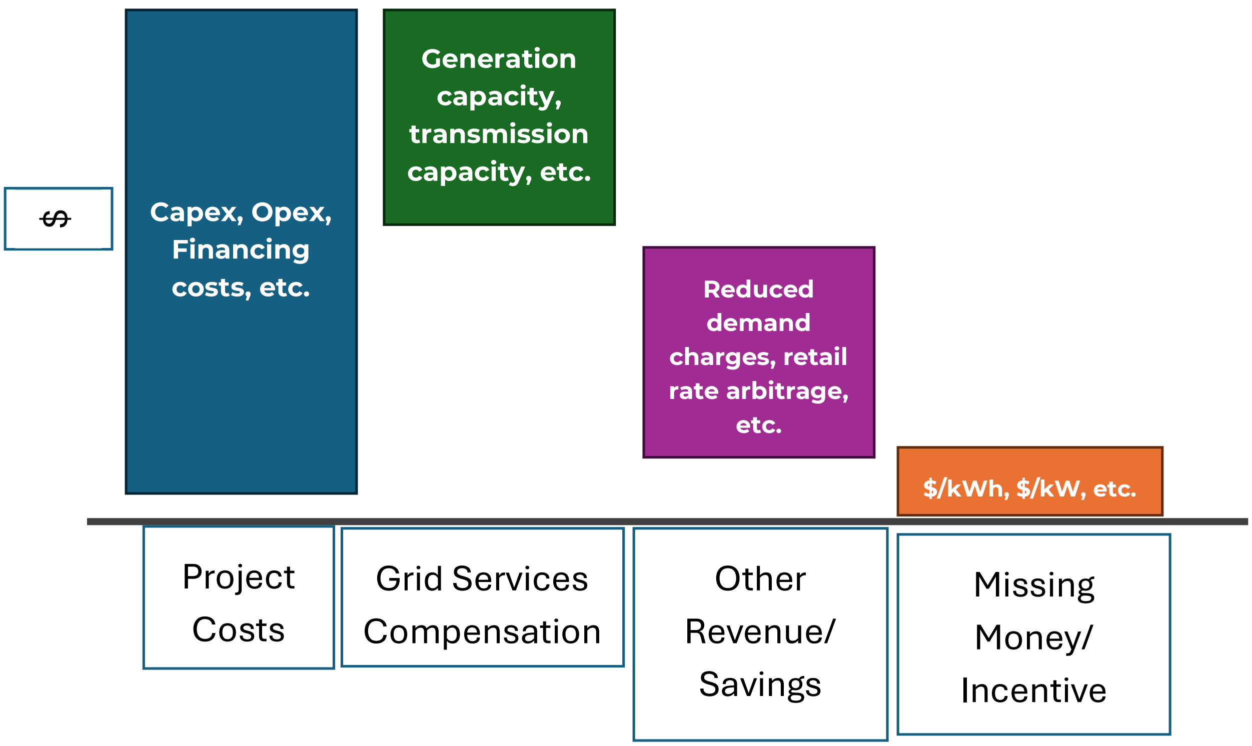
- Regarding the BCA method, the Commission has approved a UBCA framework in Phase I of Case No. 9674. Until UBCA methods consistent with this framework are further developed in Phase II of Case No. 9674, the utilities or utility contractors for electric company BCA studies should seek to align with the NSPM to the extent possible in order to remain consistent with the Commission's direction to Commission workgroups in establishing a UBCA Framework for valuing DERs, including energy storage.
- In demonstrating the benefits of their projects, electric companies should also describe any locational grid needs addressed by their project proposals including, but not limited to, the use of energy storage devices at the distribution level as non-wires solutions or improvements to the reliability of the local distribution network including integrating renewable energy sources.
- While the NSPM authors have acknowledged that the primary use of the NSPM is to develop cost-effectiveness tests to inform "investments" in DER deployment, the Respondent should specifically address what aspects of the NSPM can be adopted into the development of calculation methods in this study. For example, the NSPM provides a table of potential impacts of distributed energy storage which could be characterized as benefits factors or cost factors in this study.
- The Contractor for this study should seek to align these underlying factors with the NSPM to the greatest extent possible to remain consistent with the Commission's direction to Commission workgroups in establishing a UBCA Framework for valuing DERs.

The contractor retained to undertake the Energy Storage Program Design Study and development of a tool to determine grid service tariff values (Commission RFP# 07.01.25)—Customized Energy Solutions (CES) and Apex—presented its proposed design and methods to the MESP WG on March 12, 2026 (in which the Consultant Team participated), focusing on two elements:

1. Identifying and estimating the value of Grid Services layers for inclusion in the Grid Services Framework (GSF); and
2. Conducting a "missing money" analysis to inform the design of deployment incentives in the Deployment Incentive Framework (DIF)

The core of CES/Apex recommendations has revolved around defining a framework for a grid services tariff, assessing the potential need for an incentive to make relevant project configurations viable, and to provide the guidance and tools for utilities to conduct this work themselves. The figure below illustrates the concept of matching the expected compensation from the Grid Services Tariff and existing (or expected) revenue streams to the cost of projects to identify the missing money needed for such projects to become economically viable.

Figure: Analytical Concept



The analysis includes the following steps:

1. **Identification of potential value streams.** This includes values that may be directly monetizable by a project owner (e.g., reduced distribution and supply costs from shifting consumption to off-peak periods) as well as those that may not be (e.g., reduced greenhouse gas emissions).
2. **Categorization of potential values streams.** For each of the above, assess whether the value stream should be compensated through a Grid Services Tariff, whether it can be

realized directly by a host customer, or whether it is a benefit that cannot be monetized by the host customer and should not be included in the Grid Services Tariff.

3. **Characterization of grid services layers.** For those values to be addressed in the Grid Services Tariff, define how the benefit is realized, what behavior from the storage resources is required to produce the value, and how compensation is calculated.
4. **Definition of project configurations.** For each project configuration, define key project characteristics (e.g., project sizes, current rate class, costs), the evaluation frame (e.g., whether project economics are based on adding storage to a site that already has or was already pursuing solar vs. adding storage to a site with no solar), and source other relevant assumptions (e.g., load profile).
5. **Storage dispatch simulations.** Gather or define other information required to conduct storage dispatch modeling, such as assumptions related to future retail rates and the frequency and duration of dispatch for defined events (e.g., those associated with Distribution Capacity savings). Carry out dispatch modeling for each configuration, resulting in hourly dispatch profiles for the life of the project. See Section 8.
6. **Development and population of the financial gap calculator.** The calculator assembles relevant values from the steps above, including cost information, financing assumptions, and revenues (by individual revenue stream and year) for each configuration. It compares costs and host customer benefits on a levelized basis to assess whether a project is likely to be financially viable. Note that this is intended to be a representative project for each configuration – every actual project will have costs, revenues, and other characteristics unique to that specific project.

The CES/Apex consultant team progressed through these steps incorporating feedback from stakeholders in developing the framework. Some of the steps above will need to be repeated by utilities for initial and subsequent tariff filings and incentive proposals, if applicable.

Relevance of MD-UBCA Test and Recommended Methods

A summary of the CES/Apex list of BCA impacts to include in its tool – which aligns with the MD-UBCA Test impacts – is provided below in Table 17.

Table 17. Summary of Impacts

<table>
<tr><th>Impact Categorization</th><th>Load Reducer</th><th>Market Participant</th></tr>
<tr><td>Energy Generation</td><td>Exported energy: Grid Services Tariff (NEM customers excluded)</td><td rowspan="2">Host Customer Benefits</td></tr>
<tr><td>Generation Capacity*</td><td>Grid Services Tariff (C&I Export Only)</td></tr>
<tr><td>Ancillary Services</td><td colspan="2">Host Customer Benefits</td></tr>
<tr><td>Embedded Environmental Compliance</td><td rowspan="2" colspan="2">Captured in Energy Generation</td></tr>
<tr><td>RPS/CES Compliance</td></tr>
<tr><td>Market Price Effects - Wholesale Energy</td><td colspan="2">Grid Services Tariff</td></tr>
</table>

Market Price Effects - Wholesale Capacity	
GHG Operating Margin	
Transmission Capacity*	Grid Services Tariff and Host Customer Benefits
Transmission System Losses	Captured in Energy and Capacity value streams
Distribution Capacity	Grid Services Tariff
Distribution System Losses	Captured in Energy and Capacity value streams
Distribution O&M	
Distribution Voltage	
Financial Incentives	Host Customer Benefits
Reliability & Resilience	
System Hosting Capacity	Benefits not in Grid Services Tariff or Host Customer Benefits
Risk Mitigation	
Energy Security	
Public Health	
Equity Benefits	
Clean Energy Goal Contribution	

The CES/Apex consultant team reviewed the impacts and assigned them based on the following categorization:

1. **Quantifiable Host Customer Benefit**. Impacts that could be directly monetized or otherwise realized by a host customer were counted as a Host Customer Benefit. Quantifying these values as host customer benefits (as opposed to accounting for them through the Grid Services Tariff), ensures that a customer is not compensated for the same value twice. While these values are not compensated for through the Grid Services Tariff, they are explicitly modeled and included in the Financial Gap calculator, as they help define whether a project is likely to be financially viable or not.
2. **Grid Services Tariff**. Impacts that were deemed to be appropriate for compensation through the Grid Services Tariff were categorized as grid services impacts. At a high level, criteria considered were whether the host customer could already directly receive the benefit, whether the benefit yielded a monetizable benefit to other Maryland customers, and whether there was a means to reliably quantify the benefit.
3. **Missing Money: Not included in Grid Services Tariff or considered a Host Customer Benefit.** Some impacts could not be realized directly by customers as a benefit and were also not included as a layer in the Grid Services Tariff. These "missing money" impacts may be appropriate for consideration in energy storage incentives.

The CES/Apex consultant team has used the UBCA impact categories as a starting point for identifying candidate value streams. Although specific values associated with the benefits identified by the UBCA can be an input for compensation under the recommended Grid Services Tariff framework, the UBCA Workgroup's Phase II recommendations may include more specific recommended methodologies for how to develop estimates. In the interim, CES/Apex consultant team analysis defaults to values that are available; generally, those developed for use in evaluating EmPOWER Maryland. The CES/Apex consultant team recommends that, when values stemming from UBCA methodologies do become available, these should be used in setting Grid Services Tariff compensation rates and conducting financial gap analysis.

The UBCA Consultant Team suggests that in the immediate term, either the EmPOWER forecast method or NLR Cambium modeling approach can be used, as provided in Table 9 in Chapter 4. The JMEU specifically requested that the latter approach be used for assessing storage impacts. As noted in Subsection 4.2.1, the UBCA Consultant Team suggests that there should be flexibility to choose either approach. Decisions on which of these options to use can be informed by determination of which would be more accurate for a given type of DER, historic approaches used for a type of DER (i.e., expediency), and/or a desire for consistency across DERs, recognizing that use of the EmPOWER forecast method would provide consistency in the interim (until PSM is adopted), while the NLR Cambium model would likely be more accurate. In the long-term, the recommendation is to transition to use of the power system modeling approach, as described in Chapter 4.2.

For some of the impacts that the CES/Apex consultant team identifies as 'missing money: not included in Grid Services Tariff or considered a Host Customer Benefit,' the UBCA Consultant Team offers the following recommendations:

- **Risk Mitigation:** per the recommendation and rationale provided in Chapter 4.2.7 in this report, a 10% risk adder is appropriate to assume across all DER types, including for energy storage,[85] and can be accounted for as a monetized value as part of the grid service tariff.
- **Public Health:** per the recommendation provided in Chapter 4.6.2, public health benefits can be monetized using the modeling tool COBRA (available at www.epa.gov/cobra), and therefore could be monetized and included as part of the grid service tariff.
- **Societal Energy Security:** while this impact is included in the MD-UBCA Phase I report, as discussed earlier in Chapter 3.3, the Consultant Team recommends that that this impact not be treated as a discrete impact in the MD-UBCA Test on the basis that energy security is embedded in utility system impacts in the form of improved (or decreased) reliability and resilience of the grid, and reduce risks to the utility system and customers.
- **Equity Benefits:** per the UBCA Phase I report, equity cannot be captured in a BCA, but rather warrants a separate analysis (which the UBCA Phase II scope includes developing guidance on conducting distributional equity analysis)

[85] For Demand Response, the recommended risk adder is 5%.

Relevant Filing Schedules and Methods Implementation

The MESP Phase II report being prepared by the Energy Policy Design Institute facilitator for the MESP WG in coordination with the CES/Apex consultant team, with MESP WG input, is due to be filed with the Commission by July 31, 2026 with recommendations for a grid services tariff and deployment incentive frameworks. All assumptions will be documented with sources in a Final Report and Excel workbook tools. The grid services and incentive model tool is designed to remain useful beyond the current engagement. It will be structured as a user-adjustable tool that can continue to be utilized as key assumptions evolve over time. It is recommended that the above recommendations be considered in the final development of the storage BCA tool and underlying methods, recognizing there are limitations to coordinating the timing of this Part 1 Methods Report completion and filing with the Commission, with the MESP consultant analysis being developed concurrently to support the MESP Phase II report filing due on July 31. The Consultant Team recommends that future analyses and updates to grid tariff values consider further incorporating the UBCA Test impacts methods, where applicable, recommended in this report.

5.4. ELECTRIC SYSTEM PLANNING (ESP)

Cost-effectiveness Requirements

The cost-effectiveness requirements regarding Maryland's electric system planning are informed by Public Utilities Article ("PUA") §7-801, State's RM89 regulations (Code of Maryland Regulations, or "COMAR" 20.50.15)[86] and Commission orders in Case No. 9665. As set forth in PUA §7-801 and in the RM89 regulations, the overarching objective of the ESP is to advance the State's policy goals, including those related to renewable energy, while providing "safe, reliable, and cost-effective services". Cost-effectiveness is mentioned in consideration of solutions to electric system needs, requiring utilities to pursue industry best practice methods and analytical tools to improve their planning. RM89 regulations, specifically Section.03, states that the electric companies should use the Commission's UBCA Framework with regard to grid needs and locational value assessments, and in screening and evaluating possible solutions involving DERs. Additional details on RM89 references to cost-effectiveness testing is provided in Appendix D.

Relevance of MD-UBCA Test and Recommended Methods

The MD-UBCA Test and methods in Chapter 4 can be applied consistently across ESP investments and strategies that involve DERs as integral elements of e.g., non-wires solutions, microgrids and virtual power plants. Such application would be relevant when comparing a DER investment or strategy to a traditional distribution system investment or comparing one DER type or portfolio of DERs to a different DER type or portfolio of DERs.

Note that in the case of NWS, where a DER can defer or replace traditional utility substation upgrades, the distribution system benefit would be a function of e.g., a specific substation and the associated capital investment that would be deferred as a result of the DER. In this case, the method for monetizing benefits would not be based on the *system average*

[86] https://regs.maryland.gov/us/md/exec/comar/20.50.15

avoided distribution cost but rather on avoided *locational* costs. See additional guidance in Chapter 4.2.3 on NWS. All other impacts and methods in Chapter 4 of this report would apply.

In cases where ESP investments involve grid modernization, grid hardening, or advanced technology integration, the UBCA Test and underlying methods would not necessarily apply to these investment considerations. This is because the methods for the MD-UBCA Test are designed to assess the value of DERs relative to meeting system energy needs (e.g., increasing or reducing energy/capacity), whereas valuing investments in e.g., AMI or undergrounding wires generally do not. However, if a DER use case, such as a microgrid, is being considered as an alternative to a grid hardening investment, then the MD-UBCA Test for the DER option would account for avoided capital costs of the grid hardening option. A more basic cost-effectiveness analysis would apply to the grid hardening scenario (i.e., it would not include accounting for energy and capacity impacts). But in both cases, one would want to consistently account for applicable impacts, such as resilience, estimated over the life of the different investment options.

Table 18 describes how the MD-UBCA Test might apply to the utility electric distribution system plans depending on the grid investment and use case being analyzed. Importantly, as provided in the UBCA Phase I report (Chapter 9), while the methods recommended in Chapter 4 may not apply in all ESP use cases, the NSPM principles and key concepts can be applied broadly.

Table 18. Applicability of MD-UBCA Test to Electric System Planning Investments

<table>
<tr><th>Planning Investments</th><th>UBCA Methods Application?</th></tr>
<tr><td>Non-Wires Solutions (NWS): Procuring demand response, energy storage, or energy efficiency resources to defer or replace traditional infrastructure projects like substation upgrades.</td><td rowspan="3">Typically, yes, DERs are integral elements of these strategies and the MD-UBCA Test and methods in Ch 4 can be applied consistently across these use case scenarios, relative to traditional supply resources or even comparing one type or portfolio of DERs to a different type or portfolio of DERs.
For NWS, the distribute system benefit would be a function of e.g., a specific substation and capital investment of deferral. In this case, the method for monetizing benefits would not be based on the system average avoided distribution cost but rather on avoided locational costs. All other impacts and methods in Ch 4 of this report would apply.</td></tr>
<tr><td>Microgrids: Creating self-contained power systems with local generation (solar, storage) that can disconnect ("island") from the main grid during disasters e.g., to keep critical facilities such as hospitals, police stations running</td></tr>
<tr><td>Virtual Power Plants (VPPs): interconnected, DER devices aggregated to act as a single power plant to reduce peak demand periods</td></tr>
<tr><td>Grid Infrastructure Investments: Pole upgrades, undergrounding lines, hardening substations, upgrading transformers and lines, vegetation management, advanced conductors</td><td>Typically no. The MD-UBCA Test would not fully apply to these investment considerations because the methods in this report are designed to assess the value of a DER resource across a load profile, whereas these types of investments do not.
However, if a DER use case (e.g., a microgrid project) is being considered as an alternative to a grid</td></tr>
</table>

Advanced Technology Integration: Smart switches, sensors that identify vulnerable equipment, detect faults or reroute power; Advanced Metering Infrastructure (AMI) to provide granular, real-time data for VPPs; and DER management systems to support bidirectional power flow (solar-storage integration, EVs)	hardening investment, then the MD-UBCA Test for the DER option would account for avoided capital costs of the grid hardening option. A more basic cost-effectiveness analysis would apply to the grid hardening scenario (e.g., it would not include accounting for energy and capacity impacts). But in both cases, one would want to consistently account for applicable impacts, such as resilience, estimated over the life of the different investment options.

Relevant Filing Schedules and Methods Implementation

The Commission's ESP Order 92052 establishes a preliminary filing schedule as follows: BGE (2027), the PHI Companies – Delmarva and Pepco (2028), and Potomac Edison & SMECO (2029) unless recommended otherwise by the ESP Work Group. The Commission's Order also directed that there should be a technical conference in August of 2026 whereby Annual Plan Updates files by investor-owned electric companies will be discussed. COMAR 20.50.15.04B specifies what should be included in the Annual Plan Updates. However, in Order No. 92052, the Commission recognized that investor-owned utilities are still updating their systems and permitted them to request waivers for requirements they cannot yet meet, provided they demonstrate good cause.

5.5. NEXT GENERATION ENERGY ACT STORAGE (NGEA) DISTRIBUTION-CONNECTED PROCUREMENTS

Cost-effectiveness Requirements

The Commission Order No. 91705 on Distribution-Connected Energy Storage Procurement in Case No. 9715 (ML 319866) to implement NGEA energy storage goals set forth requirements for the electric utilities to file procurement plans as follows:

- November 1, 2025: Utilities file plans to procure 1/3 of their allotted portion of the 150 MWs of FTM distribution-connected storage
- May 1, 2026: Commission issues order approving, approving with modifications, or denying utility procurement plans.
- November 1, 2026: Utilities file plans to procure the remainder of their allotted portion of the 150 MWs.
- May 1, 2027: Commission issues order approving, approving with modifications, or denying utility plans.

The Commission's Order No. 91705 stated that "Until UBCA methodologies consistent with this framework are further developed in Phase II of Case No. 9674, the utilities or utility contractors for electric company BCA studies should seek to align with the National Standard Practice Manual ("NSPM") to the extent possible in order to remain consistent with the Commission's direction to the Commission workgroups in establishing a UBCA Framework for valuing distributed energy resources ("DERs"), including energy storage."

The Commission's Order further included application review RFP#06.02.25 for BCA Consultant services to evaluate developer applications for energy storage procurement and evaluating the utility BCAs per Order No. 91705.

In review of the utility plans filed on November 1, 2025 for the first energy storage procurement tranche, the Commission issued Order No. 92281 on April 8, 2026, with a finding that more standardization of BCAs is needed before pre-award confidential conferences, using the NSPM in alignment with the previous Commission direction given in Case No. 9674 docket regarding the work of the UBCA Work Group. This Order was followed by a report by CES to the Commission (submitting into record on April 9, 2026, in Case No. 9715) titled Memo: Review of Utility Benefit Cost Analyses for Distribution-Connected Storage. This report found that BGE had applied the MD-UBCA Test in its BCA analyses, while other utilities had used a different (or unknown) framework.

Relevance of MD-UBCA Test and Recommended Methods

The MD-UBCA Test and recommended methods in this report apply to energy storage procurements conducted under the NGEA, including both distribution-connected storage procurements in Case No. 9715 and transmission-connected storage procurements in PC 75/CN 9866, to the extent the MD-UBCA Test impacts are relevant and material to storage (as shown in Chapter 4, Tables 9 – 11). Specifically, the magnitude of the total benefits from the MD-UBCA Test can be applied to set the ceiling price above which the procurement would not be cost-effective from a quantitative perspective. However, in recognition that qualitative factors must also be considered in procurement decisions, the Commission has approved a definition of cost-effectiveness in COMAR 20.50.15.02 regulations that *““Cost-effective” means having projected benefits that are greater than projects costs while considering other factors as determined by the Commission.”* Such factors may include, for example, associated rate impacts, concerns about equity, and economic development impacts.

In discussion with CES and MESP WG Leaders, the Consultant Team’s understanding is that the review of future procurement bids will align with the MD-UBCA Test.

Relevant Filing Schedules and Methods Implementation

In Order No. 92281 issued on April 8, 2026, the Commission found that “more standardization of BCAs is needed before pre-aware confidential conferences, using the NSPM in alignment with the previous Commission direction given in Case No. 9674 docket regarding the work of the UBCA Work Group.” For this reason, a meeting to align electric company UBCA approaches has been deferred until at least July 2026, after the UBCA Work Group issues its Phase II Part 1 Methods Report.

5.6. SUMMARY OF APPLICABILITY OF MD-UBCA TEST TO MARYLAND’S OTHER WORK GROUPS

A summary of the applicability of the MD-UBCA Test to the Other WGs’ scopes is presented in Table 19. Note that the methods detailed in this report are intended to apply to all stakeholders participating in BCAs, not only the utilities, so that all parties reviewing/critiquing or conducting their own BCA models follow the same guidelines and approaches for estimating the value of the UBCA Test impacts.

Table 19. Applicability of MD-UBCA Test to Other WGs

Work Group Scope	MD-UBCA Test and Methods Applicable?
EmPOWER Programs *EmPOWER EAG*	Yes, where impacts are relevant and material to EmPOWER related DERs and subject to statutory requirements for basing goals on MDE forecasts.
MESP Strategies *MESP WG*	Yes, where impacts are relevant and material to distribution storage resources.
Energy Storage Procurement *MESP WG*	Yes, where impacts are relevant and material to distribution and transmission-connected storage resources.
PC-44 Electric Vehicle Programs *PC44-EV WG*	Yes, where impacts are relevant and material to EV managed charging programs and pricing strategies.
Electric System Plans *ESP WG*	Depends on the investment type.

6. PROCESSES AND PROCEDURES FOR MAINTAINING THE MD-UBCA TEST

The Commission's Order No. 91424 directs the UBCA Work Group to develop and propose processes and procedures to maintain the primary MD-UBCA Test and secondary tests over time and to periodically reassess the tests every four years (or more often at the Commission's discretion) to ensure that the tests continue to be consistent with state policy.

These issues of implementation and maintenance remain under consideration by the UBCA Work Group, and no recommendations on this issue are being made at this time. However, the process that is eventually proposed may serve the following purposes:

a) Overseeing and coordinating implementation of the Commission's ultimate decisions on recommended methods and timelines across Other WGs to support standardized approaches;
b) Conducting any new or updated studies to support estimation of MD-UBCA Test impacts;
c) Coordinating utilities and other stakeholders to support Commission engagement with other state agencies in the potential use of the power system modeling approach by the future Strategic Energy Planning Office (see discussion in Subsection 4.2.1); and
d) Preparing recommendations to the Commission on any needed changes to the MD-UBCA Test on a periodic basis and whenever relevant new policy directives or laws are enacted, as applicable.

This topic will be discussed in further detail amongst the UBCA Work Group and may be formally presented for Commission consideration in Part 2 of this report. No Commission action is requested on this item at this time.

Frequency of Updating Input Values

One comment that came up from utilities for several impact categories was how frequently the analyses required to estimate impacts should be undertaken, especially if the analyses are complex and require non-trivial time and effort. Related to that concern were questions about how to address situations in which there was reason to believe costs had changed materially from when the last time a study had been conducted.

This remains under discussion in the UBCA Work Group, but the Consultant Team at this time considers a 3-to-4-year cadence to be appropriate for most of the more complex analyses (e.g., PSM, electric and gas utility T&D costs). The New England Avoided Energy Supply Cost study, for example, is updated every 3 years. If there are compelling reasons to think values have become outdated because of major changes in market conditions or other factors, then updates can be made more quickly. Other methods, including those where proxy values or adders are used, may warrant review at least every 3 years or potentially more frequently. A 3-year cadence could align this review with EmPOWER plan filings.

Appendix D. Maryland Electric System Planning and Cost-Effectiveness

The ESP WG (formerly the "Distribution System Planning" Work Group)[87] was formed in 2021 and considered the statutory requirements for electric system planning in the Climate Solutions Now Act (2022) to promote a set of 12 State policy goals and also the Electric System Planning–Scope and Funding Act (2024), which among other things requires that these regulations be effective on or before December 31, 2025.

In accordance with Order No. 91490, the ESP WG filed proposed regulations on May 1, 2025. The Commission docketed a rulemaking proceeding RM89 on May 2, 2025. An RM89 rulemaking hearing was conducted on June 18, 2025, and regulations became effective on November 10, 2025.

Several parts of the approved regulations deal with cost-effectiveness, as shown below.

COMAR 20.50.15, Electric System Planning
Cost-Effectiveness References (emphasis added below)

.01 Applicability.

A. This Chapter applies to Electric System Plans for the advancement of the State policy goals and legislative intent set forth at Public Utilities Article §§7-801 – 804, *et seq.*, *Annotated Code of Maryland,* and all other relevant State goals and targets in effect during plan development. The objective of the final Electric System Plan is an electric system that advances State policy goals and is built in a manner that enables an electric company to provide safe, reliable, and **cost-effective** services and otherwise operates for the public good.

B. An Electric System Plan shall demonstrate a holistic approach to grid planning by:
   (1) Considering **cost-effective** solutions to electric system needs;
   (2) Incorporating new **cost-effective** technologies and analytical tools into planning processes to create a modern distribution system

   ....

.02 Definitions.

A. Terms Defined.

   ....

   (3) **"Cost-effective"** means having projected benefits that are greater than projected costs while considering other factors as determined by the Commission.

   ....

.03 Electric System Planning Process.

   ....

[87] The Work Group name was formally changed in Case 9665, Order No. 92317.

G. Grid Needs and Locational Value Assessment
  (1) Grid Needs assessment:

  ....

    (c) Electric companies shall **cost-effectively** pursue industry best practice methods and analytical tools to improve their planning analysis and processes, the choice of which to adopt shall be at the discretion of the electric companies.

  ....

H. Identify Possible Solutions to Grid Needs. An electric system plan shall account for the following considerations for each planning cycle and scenario:

  ....

  (2) As a Longer-Term Objective.
    (a) Electric companies shall assess the feasibility of utilizing new **cost-effective** technologies and methods for solutions to grid needs.
    (b) Electric companies shall report on the progress towards utilizing new **cost-effective** technologies and methods at annual technical conferences.
  (3) Pursuant to Public Utilities Article §7-804, Annotated Code of Maryland, electric companies shall consider investment in, or procurement of **cost-effective** demand-side methods and technology to improve reliability and efficiency, including VPPs.

I. Screen and Evaluate Possible Solutions.
  (1) An electric company shall screen and evaluate possible solutions for each planning cycle and scenario.
  (2) The electric system plan shall include the criteria used to evaluate possible solutions, including **cost-effectiveness** considerations.
    (a) Electric companies shall evaluate **cost-effectiveness** for alternatives considered.
    (b) Electric companies shall utilize the **Commission's Unified Benefit Cost Analysis framework** for solutions involving DERs in determining **cost-effectiveness.**

  ....

.04 Electric System Plan, Annual Electric System Plan Update and Preliminary Electric System Plan: Development, Reporting, and Stakeholder Engagement Process.

  ....

F. Provide Preliminary Electric System Plan.
  (1) Electric companies shall include the following in their preliminary electric system plan:

  ....

    (i) **Cost-effectiveness** analysis for identified system constraint solutions…