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Beyond Net Metering: Designing a Policy Portfolio for Measuring and Realizing the Value of Distributed Solar and Storage in Washington

October 1, 2026

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**WSAS Member*

Project Staff

DONNA GERARDI, Senior Project Director
JULIE PADOWSKI, Project Manager
EMMA ROGERS, Implementation Coordinator

Project Researchers and Consultants

TED KO, Founder, Energy Policy Design Institute
NICHOLAS MONTONI, Senior Program Director, Policy and Markets, NC Clean Energy Technology Center
PATRICK MURPHY, Senior Scientist, PSE Healthy Energy
DAN MULLEN, Writer/Editor (through August 2026)
TIMOTHY WOLF, Wolf Narrative
BART SANBORN, Sanborn Creative

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Any opinions, findings, conclusions, or recommendations expressed in this publication do not necessarily reflect the views of the organization.

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Preface

In 1998, Washington made a simple promise to residents who installed solar panels: electricity they sent to the grid would be credited at the full retail rate. Net energy metering helped a new technology gain a foothold. That period is ending. Several Washington utilities have reached their statutory enrollment thresholds, and the June 30, 2029, deadline is approaching. Meanwhile, the questions have grown more complicated. Solar is now paired with battery storage more often, electricity demand in the Northwest is rising, and the state has committed to a clean electricity system under the Clean Energy Transformation Act.

In 2024, the Legislature asked the Washington State Academy of Sciences to look ahead: to identify ways to value distributed solar and storage and to examine how policy can realize them. This report completes the second phase of that work. It builds on the Phase 1 interim report delivered in June 2025.

The committee chose not to try to produce a single number for, or a single procedure to calculate, the value of rooftop solar. Instead, the report looks at how four policy mechanisms realize a representative set of benefits and costs, and how each one, retail rate design, grid services tariffs, utility procurement, and deployment incentives, affects different groups of customers. Three findings stand out. Pairing solar with storage matters more for benefit realization than any other single factor. No single mechanism captures the full range of value, so the mechanisms are best evaluated as a portfolio. And equity outcomes depend on mechanism design choices rather than on the technology itself.

The report also identifies important knowledge gaps. For several factors, including some of particular importance to Washington such as reducing hydropower ramping, the requisite data for analysis are thin or not specific to Washington. The report identifies these gaps so that future quantitative work can address them.

I am grateful to my colleagues on the Oversight Committee, who brought expertise in power systems, economics, regulation, and equity, and who gave their time and candor generously. I also thank the WSAS project staff and consultants, whose research and writing made this report possible, and the Washington State Department of Commerce for supporting the work. We offer this report to the Legislature, the Utilities and Transportation Commission, utilities, and the public as a foundation for the decisions ahead.

Anjan Bose
Chair, Oversight Committee
Regents Professor, Washington State University

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EXECUTIVE SUMMARY

Overview

In 1998, the Washington State Legislature established net energy metering (NEM) as the state's foundational policy for compensating customers who generate their own electricity, primarily from rooftop solar, and export surplus power to the grid. The law capped each utility's NEM program at 4% of its 1996 peak demand and, once that threshold was reached, called for a reassessment of the policy. By 2024, one of Washington's largest investor-owned utilities and several public utilities had reached or neared that cap. In response the Legislature directed the Washington Department of Commerce to contract with the Washington State Academy of Sciences (WSAS) to examine the value of behind-the-meter (BTM) distributed solar and storage and to inform the design of a successor compensation framework.

This report investigates how the benefits and costs of distributed solar and storage can be quantified and expands the project's scope beyond NEM successor rates alone to a range of policy mechanisms available for scaling these resources in Washington. This report does not recommend specific compensation rates or a single preferred mechanism; rather, it lays the methodological foundation, evidence base, and design principles for building a framework to assess the value of solar and storage. The intent of this report is to provide Washington policymakers with a framework for advancing equitable and flexible solar and storage policy in future regulatory and legislative proceedings.

Why This Reassessment Is Needed Now

Two major developments make this an unusually consequential moment for Washington to reassess its distributed solar and storage policy. First, the arrival of Washington utilities at their statutory 4% NEM enrollment caps was a milestone the Legislature deliberately built into the 1998 law to force a more rigorous look at how distributed solar, and now storage, should be valued and compensated. Second, the emergence of affordable, reliable battery storage has fundamentally changed what a distributed energy resource is: a solar-only installation is largely a passive, non-dispatchable generation asset, while a solar-plus-storage system is an active grid resource that can be charged and discharged in response to price signals and dispatch needs. With the national residential solar-storage attachment rate rising from 9% in 2023 to 25% in 2024 (and even higher in California), the value of distributed solar and storage is now determined less by the hardware deployed than by the policy mechanisms that govern how that hardware operates.

A third, related development adds urgency: after a long period of flat electricity demand, the Pacific Northwest Utilities Conference Committee's load forecasts for utilities have shifted sharply upward, with regional demand now projected to grow more than 30% over the coming decade, roughly triple the rate projected only three years earlier, driven by data centers, electrification, and industrial growth.[1] Washington utility resource plans reflect a similar trend, with some utilities

[1] Pacific Northwest Utilities Conference Committee (PNUCC), *2024 Northwest Regional Forecast* (Portland, OR: PNUCC, 2024), https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf.

forecasting capacity deficits within their planning horizons absent additional energy procurement.[2] Behind-the-meter solar and storage cannot substitute for utility-scale investment at the gigawatt scale this growth implies. However, several of the benefit factors examined in this report (e.g., avoided bulk and distribution capacity costs and market price impacts) are mechanisms through which distributed energy resources (DERs) can meaningfully defer or offset system investment at the margin. This reinforces the case for policy mechanisms that guide where DERs are sited and when they operate, so that their contribution can be the greatest.

Washington's Statutory and Policy Backdrop

This analysis is bound by four Washington statutes. The Clean Energy Transformation Act (CETA, 2019) requires all retail electric sales to be greenhouse-gas neutral by 2030 and 100% non-emitting by 2045 and includes explicit equity provisions. The Climate Commitment Act (2021) sets economy-wide emissions-reduction targets and directs at least 35% of cap-and-invest revenue to vulnerable populations. The HEAL Act (2021) establishes environmental-justice expectations for clean energy planning. The Community Solar Law extends solar participation to renters, low-income households, and residents of multifamily buildings who cannot host a rooftop system. Together, these statutes make the design of distributed solar and storage compensation a matter of decarbonization, reliability, and equity policy. This is not simply a technical ratemaking exercise; these statutes give particular urgency to the choices this report is intended to inform.

In pursuing this analysis now, Washington benefits from a substantially more mature national evidence base than earlier NEM adopters had available. In 2025 alone, six states approved NEM successor programs and four released new cost-benefit studies of distributed generation. Other states have moved from simple retail-rate NEM toward value-of-solar tariffs (e.g., New York's Value of Distributed Energy Resources (VDER) "Value Stack," and California's NEM 3.0, among other successor models) providing critical insights into strategies and policies that worked well and not so well. While not directly parallel, these insights help to inform the unique situation Washingtonians face: high reliance on electricity for space heating and other end uses makes rate-design choices unusually consequential for household energy burdens; the state's integrated CETA/CCA/HEAL framework is more explicitly equity-focused than that of most other states; and hydroelectric generation provides unique opportunities for exploration of potential interactions between distributed storage operation and hydropower ramping in ways that are largely absent in other states.

Research Approach

This report builds on a scoping analysis (published June 2025[3]) that identified more than 60 potential benefit and cost factors relevant to redesigning state solar and storage policy, following an eight-step methodology. From these factors, the research team, in consultation with the

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[2] Washington State Department of Commerce, *Washington State Electric Utility Resource Planning 2024* (report to the Legislature, RCW 19.280.060).

[3] Washington State Academy of Sciences. (2025, June 30). *Interim Report: Economic Valuation of Distributed Solar Power Generation and Storage in Washington State*. https://washacad.org/wp-content/uploads/2025/07/2025_06_30-VOSS-Interim-Report-Final.pdf

project's Oversight Committee, selected a representative set of ten factors for detailed analysis, cross-referencing the National Standard Practice Manual and a prior Washington-specific value-of-solar study by E3. The ten selected factors included: eight benefits (avoided energy costs, avoided bulk capacity costs, avoided distribution capacity costs, market price impacts, host customer resilience, hydropower ramping interactions, improved economic wellbeing, and job creation/economic development) and two costs (increased bulk capacity costs and increased distribution capacity costs). This set was chosen to demonstrate how different factors can be applied and combined to meet specific provider or community needs, and not to provide an exhaustive accounting of every relevant benefit and cost.

Moreover, given existing Washington statutes, an equity lens was used to analyze each factor against the four primary policy mechanisms through which U.S. jurisdictions deploy and direct behind-the-meter solar and storage. Analyses separately accounted for both solar-only and storage-enabled configurations.

Policy Mechanisms Evaluated in this Study

- **Retail rate design:** Export compensation (NEM, value-of-solar, net billing), time-of-use rates, demand charges, and fixed charges. Rate design is scalable and foundational, but coarse: it cannot easily price locational value, and mis-set export compensation can create a cost shift to non-participants.
- **Grid services tariffs:** Standing programs that pay for measured grid services such as capacity relief. These tariffs are precise and capable of capturing locational value, but are budget-limited and dependent on careful dispatch calibration.
- **Utility procurements:** Competitive contracts through which utilities acquire dispatchable capacity from aggregators or virtual power plants. These procurements offer the greatest potential for net-positive ratepayer value as the market matures, but are slower and more transaction-intensive.
- **Deployment incentives**: Rebates, grants, and performance payments that lower installation cost and directly expand the addressable market, but do not by themselves ensure that deployed assets later operate in ways that realize grid value.

Since these four mechanisms are not mutually exclusive and because their effects on distributed solar and storage adoption, use, and benefits are interdependent, this report evaluates these policy mechanisms as a portfolio rather than in isolation.

Principal Findings

The central finding in this report is structural: the way a policy mechanism is designed doesn't just decide how the value of distributed energy resources is divided up, it can shape how much value gets created in the first place. How much of a system's theoretical value is actually realized, and who receives it, depends almost entirely on the policy mechanisms that govern how it operates, so the governing policy question is not "what is the value of solar and storage?" but "what combination of mechanisms will direct these resources to create the most value for Washington's ratepayers and citizens?" Therefore, this report does not produce a single dollar figure for the value of distributed solar and storage in Washington, nor does it recommend specific compensation levels or a preferred mechanism.

Benefit Realization

- The complementarity between solar panels and storage is the single most consequential variable for impacting the extent to which the potential benefits of distributed solar and storage are achieved or realized. Storage-enabled installations realize higher or equal benefits than solar-only installations across every factor examined, and solar-only systems realize little or no bulk capacity, distribution capacity, or resilience value under any mechanism. When designed effectively, policy mechanisms were found to actively promote storage attachment through time-of-use (TOU) differentials, storage-specific grid services compensation, and enhanced incentive rebates that are sized to reflect the value storage provides.
- No single policy mechanism fully realizes the range of benefits. However, the four mechanisms are structurally complementary: retail rate design is best suited to avoided energy costs; grid services tariffs and utility procurements are best suited to capacity value; and deployment incentives are best suited to host customer resilience, distributional equity, and driving deployment volume. This finding suggests that coordinated portfolios may bring greater benefits than any single policy mechanism alone.
- The quality of policy mechanism design matters as much as mechanism choice. Time-differentiated rates, explicit capacity-value components, locational differentiation, and operational requirements tied to eligibility for incentives are the design features most consequential for whether a policy mechanism realizes its potential benefit.
- Hydropower ramping reduction is a Washington-specific policy innovation opportunity. No U.S. jurisdiction has yet designed a mechanism to compensate storage specifically for reducing hydropower ramping. While acknowledging the complexity of doing so, given the centrality of hydroelectric generation to Washington's system, the state is uniquely positioned to explore the feasibility of developing and piloting one.
- Market price reductions from distributed solar and storage investment (such as demand reduction induced price effect (DRIPE) are a portfolio-level co-benefit, not a factor any single mechanism can target directly.

Cost and Equity

- The cost shift to non-participating ratepayers is the dominant and most contested cost equity concern, and it is concentrated in retail rate design. In addition, the estimated magnitude of the cost shift depends heavily on which system benefits are included in the analysis. This report examines the underlying empirical debate but does not specifically attempt to resolve these key issues.
- Increased system costs from the addition and maintenance of storage are manageable under appropriate policy mechanism design (e.g., dispatch requirements and time-of-use incentives that align charging and discharging with system needs), but can be significant without it. The risk is therefore a function of policy mechanism design choices, not of the storage technology itself.
- The cost shift and increased system costs interact through rate design, making it useful to analyze them together rather than independently. For example, rate adjustments that address only cost shift or system costs can worsen the other, particularly for low- and moderate-income households.

- Ratepayer-funded deployment incentives can produce negative outcomes for some ratepayers if deliberate low-to-moderate income (LMI) targeting is not considered first. Well-calibrated incentive levels, declining block structures, and LMI-targeted provisions, or limiting ratepayer-funded incentives to the value of the benefit provided, and funding additional adoption goals through non-ratepayer sources, are likely primary tools for managing this type of risk.
- Equity is treated throughout this analysis rather than as a separate topic. Absent deliberate design, benefits tend to concentrate among higher-income, owner-occupied households while costs and unmet resilience needs fall disproportionately on lower-income, renting, and disadvantaged communities. The report identifies, but does not resolve, equity gaps that further research will need to address, including the implications of hydropower-dependent policy design and distributed energy resources for Tribal communities, particularly in light of the significant impact of Washington's 2026 wildfire season on Tribal grid reliability.

Portfolio Design and Sequencing

- This report suggests that state strategies implementing single policy mechanisms for single benefits may forgo the benefits of a well-considered portfolio of policy mechanisms. As load growth accelerates and major resource decisions are being made now, the state has a timely opportunity to design a coordinated portfolio that maximizes combined benefits, consistent with the intent of its forward-thinking energy statutes.
- This report also suggests a general approach for policymakers, regulators, and communities to consider in which the mechanisms are developed in parallel rather than one after another, each playing a different role over time. Retail rate design reform can begin now, since utilities are reaching their NEM caps, though it will take time to complete. Development of grid services tariffs can also begin right away, with replacing NEM export compensation as the first priority. Laying in the full range of benefits will also take time. In the meantime, a deployment incentives can keep the marketing for deployed resources moving forward while the other two mechanisms are explored and developed. Utility procurement is best reserved for meeting specific grid needs, or for cases where it is more cost-effective than a grid services tariff. Over time, new combinations of policies could emerge as the distributed resources market matures.

State of the Evidence

The methodological literature is well developed for avoided energy and bulk capacity costs and moderately developed for market price impacts and distribution capacity and resilience benefits. In addition, while documented cost-effectiveness studies that evaluate individual programs and specific benefits exist, they rarely assess these in the context of diverse policy mechanism portfolios, which limits our understanding of the potential benefits that could be realized. Moreover, little evidence for hydropower ramping reduction and the Tribal equity dimensions of distributed resource policy currently exists. Finally, Washington-specific data (e.g., utility load profiles, avoided cost schedules, hosting capacity maps, hydroelectric dispatch data, and income/energy-burden distributions) will need to be assembled before Washington-specific quantitative estimates can be produced for regulatory use.

What This Report Provides, and What Still Needs to be Done

This report provides several contributions: a comprehensive, cross-referenced taxonomy of benefit and cost factors; a documented approach for the selection of a representative subset of factors for analysis; quantification methods for the ten selected factors; qualitative characterizations of how effectively each of the four mechanisms realizes each benefit and incurs cost for both solar-only and storage-enabled systems; and a set of cross-cutting design principles for a Washington policy portfolio, along with an explicit account of research gaps and data needs.

Washington-specific dollar estimates of any benefit or cost factor, a recommendation of specific export compensation rates or incentive levels, a definitive ranking of policy mechanisms, or a complete benefit-cost analysis of any specific utility's program or tariff proposal require Washington-utility specific data and modeling that lie outside this project's scope. These will need to be developed through the regulatory and legislative proceedings that this report, and its companion implementation manuals, are intended to inform.

I. STATUTORY BACKGROUND AND PROJECT AUTHORIZATION

In 1998, the Washington State Legislature enacted ESHB 2773[4], establishing net energy metering (NEM) as the state's foundational policy for compensating customers who generate electricity from renewable systems, primarily solar, and export surplus power to the grid. Codified at RCW 80.60[5], the statute directed utilities to offer NEM on a first-come, first-served basis, crediting exported generation at the full retail electricity rate applicable to the customer class. The Legislature identified three public interest objectives motivating this policy: encouraging private investment in renewable energy resources, stimulating state economic development, and enhancing the diversification of Washington's energy supply portfolio.

Under the statute, participating customers receive credit for exported electricity at the full retail rate. The 1998 law also embedded a built-in review mechanism: each utility's NEM program was capped at 4% of its 1996 peak electricity demand, and once that threshold was reached, or closely approached, a reassessment of the policy's appropriateness was expected.

By 2024, that moment had arrived. One of Washington's investor-owned utilities and several of its public utilities had reached or were nearing the 4% enrollment cap. As utilities started to arrive at this threshold, the Legislature directed the Department of Commerce to contract with the Washington State Academy of Sciences (WSAS) to examine the value of behind-the-meter (BTM) distributed solar and storage, i.e., solar power generated on the customer's side of the electricity meter (e.g., rooftop panels), where the energy is used directly by the home or business instead of first going to the grid, and to develop recommendations for future compensation structures. The legislative language for two phases of work are included in Boxes 1 and 2. This report explores moving beyond NEM's original structure and gives policymakers the analytical grounding needed to design future approaches.

[4] Washington State Legislature, House Committee on Energy & Utilities. (1998). *House Bill Report: SHB 2773* (as passed legislature). https://lawfilesext.leg.wa.gov/biennium/1997-98/Pdf/Bill%20Reports/House%20Historical/2773-S%20BRH%20PL.pdf

[5] Revised Code of Washington. (n.d.). Chapter 80.60: Net Metering of Electricity. https://app.leg.wa.gov/rcw/default.aspx?cite=80.60

Box 1. Value of Solar and Storage, FY 25, Engrossed Substitute Senate Bill 5950 (2024), Sec. 102 (117)

The Department of Commerce shall:

(a) "contract with the Washington state academy of sciences to conduct a study to determine the value of distributed solar and storage in Washington state, including any factors the academy finds relevant, in order to create recommendations and options for a methodology or methodologies that utility regulators and governing bodies may use after the statutory four percent net metering threshold is met. In the course of their research and analysis, the academy shall engage relevant stakeholders focused on the value of distributed energy resources in Washington state, including solar, storage, vehicle to grid, and other resources. This shall include, but is not limited to, representatives from consumer-owned utilities, municipal-owned utilities, investor-owned utilities, utility regulators, the rooftop solar and storage industry, as well as advocacy organizations involved with consumer advocacy, environmental justice, clean energy, climate change, labor unions, and federally recognized Indian tribes."

(b) "The Washington State Academy of Sciences shall submit an interim report to the department and the utilities and transportation commission by June 30, 2025. This interim report must include a plan and cost estimates for further work in the 2025-2027 fiscal biennium to develop policy recommendations and submit a final report to the department and the utilities and transportation commission."

Box 2. Value of Solar and Storage, FY 26 - FY 27 Engrossed Substitute Senate Bill 5167, Section 133(17)(2)

The WSAS shall:

"complete a study to determine the value of distributed solar and storage in Washington state. Including any factors that it finds relevant, the academy shall develop policy recommendations and options for methodology or methodologies that utility regulators and governing bodies may use after the statutory four percent net metering threshold is met. The academy shall submit a final report to the department and the utilities and transportation commission by October 1, 2026."

WSAS organized the work in two phases, **Phase 1** (July 2024 to June 2025) and **Phase 2** (July 2025 to September 2026). Phase 2, which this report documents, built on the foundation laid in Phase 1 by investigating how benefits and costs can be quantified and by expanding the scope from NEM successor rates alone to the range of policy mechanisms available for scaling distributed solar and storage in Washington.

II. POLICY AND REGULATORY CONTEXT

Historical Development of Net Energy Metering Policy

Net energy metering emerged nationally in the 1980s as states sought to encourage small-scale renewable generation in the wake of the federal Public Utility Regulatory Policies Act (PURPA) of 1978. NEM's central appeal was its simplicity. Rather than attempting to quantify the precise value of rooftop solar to the grid, it offered a straightforward proposition: customers who generate more electricity than they use at any given moment can "run the meter backward," receiving credit at the same retail rate they pay for power from the utility. By the end of the 1980s, seven states had adopted NEM; by 2016, 45 states plus the District of Columbia and three territories had followed suit.[6, 7]

Washington joined this national movement in 1998. The Legislature's purpose was clear: to encourage private investment in renewable energy, stimulate economic growth, and diversify the state's energy mix. The economics were transparent enough to drive adoption. For more than two decades, it worked. Washington's NEM capacity grew steadily as various utilities closed in on the 4% threshold[8] and solar installations spread across residential and commercial rooftops statewide.

As distributed solar penetration increased, the theoretical and practical limitations of the retail-rate NEM model became more apparent. The retail electricity rate aggregates costs spanning multiple system tiers—bulk generation, transmission, distribution, and fixed grid infrastructure—as well as non-bypassable charges for public purpose programs (Table 1). Compensating solar exporters at this bundled rate results in systematic mismatch: customer-generators are compensated for grid services they may not be providing (e.g., distribution capacity relief during periods when their exports do not coincide with local peak demand) while not being compensated for grid services they do provide but that are not captured in the broader rate structure. Additionally, retail-rate NEM effectively allows NEM participants to reduce their contribution to shared grid cost recovery without a corresponding reduction in their reliance on grid infrastructure, creating a potential cost-allocation inequity for non-participating ratepayers, particularly those in lower-income households who may be unable to invest in rooftop solar systems. Critics of NEM have also raised fairness concerns: customers without rooftop solar (disproportionately renters and lower-income households, but also those whose houses are not located in areas with abundant solar conditions) effectively subsidize the bill savings of those who can afford to install panels.

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[6]National Academies of Sciences, Engineering, and Medicine. (2023). *3 Background and History, Current Status, and Near-Term Future of Net Metering.* In The Role of Net Metering in the Evolving Electricity System (p. 35). Washington, DC: The National Academies Press. https://doi.org/10.17226/26704

[7] ibid.

[8]Washington State University Energy Program. (2026, January). *Net metering statistics for utility companies in Washington State*. https://wpcdn.web.wsu.edu/cahnrs/uploads/sites/60/2026/03/WSU-EP-Net-Metering-Statistics-January-2026.pdf

Table 1. Components embedded in a retail electricity rate

Component / Tier	What It Represents	Cost Elements Included	Role in Retail Rate
Bulk Generation (Supply)	Production of electricity at power plants	Fuel costs, plant construction, operations, maintenance, capital recovery	Typically the largest share of the rate; reflects the cost to produce power
Transmission	High-voltage movement of electricity over long distances	Transmission lines, substations, regional grid operations, maintenance	Moves electricity from generators to regional/local distribution systems
Distribution	Local delivery of electricity to end users	Poles, wires, transformers, metering, local system maintenance	Final stage delivering power to homes and businesses; largely fixed infrastructure costs
Fixed Grid Infrastructure Charges	Costs independent of usage, tied to maintaining grid access	Customer service, billing systems, meter infrastructure, baseline grid readiness	Ensures utilities recover ongoing costs of maintaining reliable service regardless of consumption
Non-Bypassable Charges (Public Purpose & Regulatory)	Mandatory system-wide fees applied to all customers	Energy efficiency programs, low-income assistance, legacy system costs (e.g., stranded assets, decommissioning), policy mandates	Fund public benefit programs and shared system obligations that all grid users must support

Beginning in the 2010s, new approaches to distributed energy policy emerged, characterized by "value of solar" (VoS) studies and tariffs. VoS approaches sought to quantify, through utility-specific modeling, the net benefits of distributed solar photovoltaic (PV) panels across system tiers and from multiple perspectives (utility, ratepayer, and societal), and to set export compensation accordingly. Early VoS implementations, including Austin Energy's value-of-solar tariff[9] and the Minnesota value-of-solar methodology established under Minn. Stat. § 216B.164,[10] demonstrated the feasibility of more granular benefit attribution but also revealed the methodological complexity and contested assumptions inherent in any comprehensive valuation exercise.

[9] City of Austin, Austin Energy. (2026). *Value of Solar (VoS) Rates*. https://austinenergy.com/rates/residential-rates/value-of-solar-rate

[10] Minnesota Statutes. (2025) *§ 216B.164: Cogeneration and Small Power Production*. https://www.revisor.mn.gov/statutes/cite/216b.164

The national policy evolution beyond traditional NEM has proceeded with several innovative and novel successor initiatives across many states. Unlike New York's Value of Distributed Energy Resources (VDER) tariff with its "Value Stack", which applies mainly to community solar and larger non-residential projects while rooftop solar customers remain on net metering, California's NEM 3.0 applies directly to new residential and small commercial customers.[11, 12] The most recent phase of distributed energy policy arguably began in 2023 with California's adoption of its NEM 3.0 tariff, which dramatically reduced export compensation for new solar installations and effectively required pairing with battery storage to make the economics work. This policy does not cover residential and small business customers in the same way as NY's VDER, and the transition produced significant near-term market disruption, particularly for the residential solar installation industry, and generated considerable controversy. California's experience has been instructive and cautionary, underscoring the importance of policy transition design, market certainty, and the interplay between export compensation structures and storage adoption incentives.[13]

Washington's 4% enrollment cap trigger, and the resulting legislative direction to WSAS, positions the Legislature to take a rigorous look at the value of distributed solar, and now storage, and how that value could be reflected in policy going forward. It also leaves the state designing its own successor framework at a moment when the national evidence base on distributed energy policy has had time to evolve and mature in many states. That experience makes it an opportune time to design and implement new ideas, creating a perfect opportunity to learn from examples in other states and design programs that are appropriate for Washington State's wide variety of utilities.

Washington State's Clean Energy Policy Framework

The analytical and policy context for this report is shaped by a suite of Washington State statutes that collectively establish binding decarbonization targets, environmental justice obligations, and clean energy planning requirements for the state's electric utilities. These statutes are not merely aspirational; they impose enforceable obligations with specified compliance timelines and create the regulatory environment within which distributed solar and storage policy must be situated.

The Clean Energy Transformation Act (CETA), enacted as SB 5116[14] in 2019 and codified at RCW 19.405[15], is the central instrument of Washington's electricity sector decarbonization strategy. CETA requires that all retail electric sales in Washington be greenhouse gas (GHG) neutral by 2030 and that 100% of the electricity used for retail sales be derived from non-emitting sources by 2045.

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[11] VDER compensates distributed solar and storage using a "value stack" that separates payments into distinct components, each tied to market signals or system costs. This replaces traditional flat rates with a dynamic approach that varies by time, location, and actual grid benefits, aligning compensation with wholesale market conditions and localized system needs.

[12] New York State. (2016, March). *Reforming the Energy Vision (REV)* [white paper] https://www.ny.gov/sites/default/files/atoms/files/WhitePaperREVMarch2016.pdf

[13] California Public Utilities Commission. (2022, December 15). *Decision Adopting the Net Billing Tariff, Decision (D.) 22-12-056, Rulemaking (R.) 20-08-020*. (Issued Dec. 19, 2022) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF

[14] Washington State Legislature. (2019). *Substitute Senate Bill 5116, 2nd Engrossed: Supporting Washington's clean energy economy and transitioning to a clean, affordable, and reliable energy future*. 2019 Wash. Sess. Laws ch. 288. https://app.leg.wa.gov/billsummary?Year=2019&BillNumber=5116

[15] Revised Code of Washington. (2025). *RCW 19.405: Washington Clean Energy Transformation Act*. Washington State Legislature. https://app.leg.wa.gov/rcw/default.aspx?cite=19.405

To meet the 2030 interim target, each utility subject to CETA must ensure that at least 80% of its electricity for retail electric load is supplied by non-emitting generation or renewable resources. CETA also includes explicit equity provisions, requiring utilities to pursue the equitable distribution of energy benefits and the reduction of energy burdens for vulnerable populations and highly impacted communities, and directing revenues from the clean energy standard to the Low-Income Weatherization and Structural Rehabilitation Assistance Fund.

The Climate Commitment Act (CCA)[16], enacted in 2021 and codified at Chapter 70A.65 RCW[17], establishes a cap-and-invest program requiring major greenhouse gas emitters to purchase emissions allowances from a declining pool. The CCA sets economy-wide GHG reduction targets at 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels, with net-zero emissions, by 2050[18]. At least 35% of CCA revenues must be directed to investments that provide direct benefits to vulnerable populations. The CCA interacts with CETA by creating economy-wide decarbonization pressure that increases the relative value of non-emitting electricity resources, including distributed solar and storage.

The Healthy Environment for All (HEAL) Act, also enacted in 2021 and codified at Chapter 70A.02 RCW[19], requires certain state agencies to incorporate environmental justice considerations into their planning and budgeting decisions. While electric utilities and the Washington Utilities and Transportation Commission (UTC) are not directly covered agencies under HEAL, the Act reinforces equity norms that pervade CETA and the CCA and establishes a statutory expectation that clean energy policy, including policy governing distributed solar and storage, will be designed with explicit attention to its distributional consequences.

Washington's Community Solar Law, in effect since 2017, modified in 2022, and codified in Section 82.16.183 RCW, supports community solar programs with the goal of broadening and diversifying participation in solar energy generation. Eligible projects are limited to 199 kilowatts or smaller and must have at least two subscribers or one low-income service provider subscriber. Community solar provides an access pathway for customers who cannot host rooftop installations, including renters, low-income households, and those in multifamily dwellings, and, while different in some ways, is therefore a relevant complement to BTM solar policy in the state's distributed energy portfolio.

Taken together, these statutes establish an energy policy environment in which the design of distributed solar and storage compensation frameworks is not merely a technical ratemaking question but a matter of direct consequence for Washington's ability to meet its legally mandated decarbonization, reliability, and equity objectives. The scope and ambition of these commitments,

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[16] Washington State Department of Ecology. (2025). *Climate Commitment Act*. https://ecology.wa.gov/air-climate/climate-commitment-act

[17] Revised Code of Washington. (2025). *Chapter 70A.65 RCW: Greenhouse gas emissions—Cap and invest program*. Washington State Legislature. https://app.leg.wa.gov/rcw/default.aspx?cite=70A.65

[18] Net-zero emissions are achieved in the absence of 100% GHG reductions by enhancing neutral carbon sinks (e.g., forests) and/or deploying emerging technologies (e.g., direct air capture).

[19] Revised Code of Washington. (2025). *Chapter 70A.02 RCW: Environmental justice*. https://app.leg.wa.gov/rcw/default.aspx?cite=70A.02&full=true.

and the compressed timelines they impose, give particular urgency to the policy choices this report is intended to inform.

The Significance of Affordable Energy Storage

Any analysis of Washington's distributed solar and storage policy that does not account for the transformation produced by commercially available battery energy storage would be incomplete. When ESHB 2773 was enacted in 1998, pairing residential or commercial solar installations with on-site battery storage was economically impractical for virtually all utility customers. The policy environment accordingly treated distributed solar as a generation-only resource, one whose value was a function primarily of its production profile and the extent to which that profile aligned with system needs.

The emergence of affordable, reliable battery storage fundamentally alters the value proposition of BTM energy resources. A solar-only installation is, practically speaking, non-dispatchable: it produces electricity when and in the quantities that irradiance conditions permit, without regard for whether that generation coincides with system peak demand, distribution capacity constraints, or periods of high wholesale market prices. The result is a resource whose benefits are largely passive and whose operational profile cannot be directed by policy signals.

A solar-plus-storage installation, by contrast, is dispatchable within the limits of its stored energy and power capacity. Battery storage enables time-optimized energy use, e.g., charging during periods of low-cost, high-generation conditions and discharging during periods of high-cost, high-demand conditions, as well as deliberate response to utility dispatch signals, time-of-use rate incentives, and demand charge management objectives. This dispatchability transforms the distributed solar-plus-storage system from a passive generation asset into an active grid resource capable of providing a substantially broader array of grid services.

The pace of storage adoption reflects these changed economics. Lawrence Berkeley National Laboratory reports that the residential solar attachment rate for battery storage nationally rose from 9% in 2023 to 25% in 2024.[20] In California, where NEM 3.0 restructured export compensation to favor storage-augmented systems, 57% of new residential solar installations were paired with battery storage in 2024.[21] These figures signal a structural shift in the distributed energy market that policy frameworks designed for solar-only resources are not equipped to capture.

The policy implication is significant and is developed at length in this report: the value of BTM distributed solar and storage is no longer primarily a function of the hardware deployed, but of how that hardware operates, and how it operates is a function of the policy mechanisms that govern it. This insight is described in Section V below.

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[20] Lawrence Berkeley National Laboratory. (2025). *Distributed Solar & Storage – 2025 Data Update*. https://emp.lbl.gov/sites/default/files/2025-10/Distributed%20Solar%20%26%20Storage-2025%20Data%20Update.pdf
[21] ibid.

The Emerging Challenge of Load Growth and the Potential Contribution of Distributed Solar and Storage

The policy and regulatory context described above has, until recently, been shaped primarily by a period of relatively flat or slow-growing electricity demand in the Pacific Northwest. That period has ended. Regional load forecasts have shifted markedly in just the past few years: the Pacific Northwest Utilities Conference Committee's 2024 regional forecast projected electricity demand across Oregon, Washington, Idaho, and Montana to grow more than 30% over the coming decade — roughly triple the growth rate projected only three years earlier — driven by large data centers, high-tech manufacturing, and accelerating electrification of buildings and transportation.[22] The Northwest Power and Conservation Council's most recent 20-year outlook similarly projects regional annual energy demand rising from approximately 22,000 average megawatts (aMW) today to between 31,000 and 44,000 aMW by 2046, depending on the growth trajectory realized.[23]

This acceleration is visible in Washington-specific resource planning as well. Under the state's utility resource planning statute, each electric utility must periodically forecast the electricity its customers will require over the coming decade and identify the resources needed to meet that demand.[24] Washington utilities' most recent filings reflect the same upward shift seen at the regional level: Avista's 2025 Integrated Resource Plan projects annual demand growth of roughly 0.9%, with winter peak demand growing faster still, at about 1.14% annually.[25] Clark Public Utilities projects average annual load growth of nearly 2%--and as high as 3.1% under a high-growth scenario–through 2044, driven substantially by building and vehicle electrification, and forecasts a growing capacity deficit, reaching roughly 750 MW in summer and 500 MW in winter by the end of its planning horizon absent additional resource procurement.[26] Other Washington utilities, particularly those serving central Washington, have seen load growth driven substantially by the arrival of large data centers.[27, 28]

Electric vehicle charging alone is projected to account for a meaningful share of this growth: regional forecasts anticipate EV charging load reaching roughly 4% of total West-wide electricity

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[22] Pacific Northwest Utilities Conference Committee (PNUCC). (2024). *2024 Northwest Regional Forecast*. https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf
[23] Northwest Power and Conservation Council (NWPCC). (2025, May 2). *Pacific Northwest Load Forecast 2025*. https://www.nwcouncil.org/news/2025/05/02/pacific-northwest-load-forecast-2025/
[24] Revised Code of Washington. (2025). *Chapter 19.280 RCW: Electric Utility Resource Plans*. Washington State Legislature. https://app.leg.wa.gov/rcw/default.aspx?cite=19.280&full=true
[25] Avista Utilities. (2025, January 2). *2025 Electric Integrated Resource Plan*. Filed with the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission. https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2025/2025-avista-electric-irp.pdf
[26] Clark Public Utilities. (2024). *2024 Integrated Resource Plan*. https://www.clarkpublicutilities.com/wp-content/uploads/2024/08/CPU-2024-IRP_FINAL-Version-2-BPA-LF.pdf
[27] Western Electricity Coordinating Council (WECC). (2025). *2025 State of the Interconnection*. https://www.wecc.org/sites/default/files/documents/communications/2025/WECC_State_of_the_Interconnection_2025.pdf
[28] Grant County Public Utility District No. 2. (2024, August 27). *2024 Integrated Resource Plan* [Approved by the Commission]. https://www.grantpud.org/block/documents/66c7ca72740aa-2024-08-27-commission-meeting-packet.pdf

demand by 2034, with some Washington utilities, including Seattle City Light, projecting EV-driven demand growth in their own service territories well above that regional average.[29]

This shift in the demand outlook adds a resource-adequacy dimension to the policy question this report addresses, alongside the decarbonization, affordability, and equity dimensions already described in Section II. Historically, Washington's NEM policy and its potential successors have been evaluated primarily as instruments for encouraging customer investment in renewable generation and for allocating the costs and benefits of that investment fairly among ratepayers. As utility load forecasts rise, this report explores the role that behind-the-meter distributed solar and storage can play in helping utilities meet growing demand, particularly at the margin, where new capacity is most costly to procure.

The scale of that potential contribution should not be overstated. The gigawatt-scale load growth anticipated from data centers and industrial electrification in parts of Washington is unlikely to be met, even in significant part, by behind-the-meter deployment alone; utility-scale generation, transmission, and storage investments will remain the primary tools for meeting bulk system needs. At the margin that matters for planning purposes, however, the contribution of distributed solar and storage need not be large to be useful. As discussed further in Sections IV and VI, several of the benefit factors examined in this report–avoided bulk capacity costs, avoided distribution capacity costs, and market price impacts–are, by definition, mechanisms through which distributed resources can offset or defer the need for new system investment, even at modest levels of deployment. And as discussed in Section V, several of the four primary policy mechanisms, particularly utility procurements structured as non-wires alternatives (a distributed resource used in place of a traditional grid upgrade) and grid services tariffs targeting capacity-constrained periods, are specifically designed to translate distributed capacity into deferred or avoided system investment.

This report does not attempt to quantify the magnitude of that potential contribution in the Washington context; doing so would require utility-specific load forecasts, hosting capacity data, and modeling that lie outside the scope of this work. But the growing gap between Washington's projected electricity demand and its currently planned resources is an important and evolving piece of context for the policy discussion that follows, and it strengthens, rather than diminishes, the case for designing policy mechanisms that direct distributed solar and storage toward the specific times, locations, and operating conditions where that contribution has the greatest value.

[29] Ibid.

III. NATIONAL POLICY CONTEXT

This section situates Washington's re-evaluation of NEM within a national context, identifying the principal phases of distributed energy policy evolution and noting, briefly, the state-level examples that this report draws upon in subsequent sections. Across the country, states are grappling with the same fundamental question: as distributed solar penetration grows and the technology landscape evolves, how should these resources be valued and compensated, and what policy mechanisms can best translate their potential into realized benefits for customers, utilities, and the public?

Today, activity in this space is intensifying nationwide. The NC Clean Energy Technology Center reported 49 states, plus the District of Columbia and Puerto Rico, took some type of distributed solar policy action in 2025, with net metering, community solar, and fixed charges as the most common state-level policy actions.[30] Four states (Delaware, Illinois, Massachusetts, and Wisconsin) released cost-benefit analyses or study reports on distributed generation in 2025 alone. Six states approved NEM successor or similar programs that year. In Washington, the state's first investor-owned utility to reach the NEM cap, PacifiCorp, has a successor tariff currently under consideration at the Utilities and Transportation Commission.[31] Other states actively studying or reforming their distributed generation policies and valuation methods, or having made changes to NEM in the last decade, include:

- New York, where the Public Service Commission is actively considering updates to the Value of Distributed Energy Resources (VDER) program, with decisions pending on the adoption of a staff proposal;[32]
- Nevada, where the Public Utilities Commission approved NV Energy's shift from monthly to 15-minute netting for new rooftop solar customers in Northern Nevada, along with a new daily demand rate for residential and small business customers in Southern Nevada. The decision is subject to a petition for judicial review;[33]

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[30] NC Clean Energy Technology Center. (2026, January 22). *The 50 States of Solar: 2025 Annual Review and Q4 Update*. https://nccleantech.ncsu.edu/2026/01/22/the-50-states-of-solar-states-focus-on-value-of-distributed-generation-advanced-rate-designs-and-energy-storage-in-2025/

[31] Under PacifiCorp's proposed Net Billing program, enrolled customers would receive bill credits determined by multiplying energy exported from the customer to the utility grid by an export credit price, which PacifiCorp calculated at 5.167 cents per kilowatt-hour (kWh), subject to annual updates. Additionally, PacifiCorp proposed an Equitable Access Credit which would allow customers enrolled in the Low Income Bill Assistance program to continue receiving the same economic benefits of Net Metering that were previously available to early adopters who could afford onsite generation systems. https://www.utc.wa.gov/casedocket/2025/250695

[32] New York State Electric and Gas Corporation. (n.d.). *Summary of Cumulative Economic Carrying Charges by Substation Area*. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={20C6139B-0000-C34D-B2CD-CB995B9E2CA3}&DocTitle=Staff_DRV_LSRV_Proposal_Workpaper

[33] Walton, R. (2025, September). Regulators approve demand charge, net metering changes for NV Energy. *Utility Dive*. https://www.utilitydive.com/news/regulators-approve-demand-charge-net-metering-changes-for-nv-energy/760485/

- South Carolina, where the Public Service Commission recently approved a change to allow distributed solar crediting across time-of-use rates of equal or lesser value;[34]
- Arkansas, where Act 278 ended NEM and transitioned customers to net billing;[35]
- Connecticut, where the legislature enacted H.B. 5340 requiring the Public Utilities Regulatory Authority to establish a NEM successor;[36]
- Maryland, where the legislature enacted H.B. 1532 requiring the Public Service Commission to establish a NEM successor;[37]
- Hawai'i, where the Public Utilities Commission closed NEM in 2015 but has consistently created new distributed generation programs like the Smart DER (Distributed Energy Resources) that includes several program options;[38]
- Vermont, where the Public Utilities Commission has made consistent cuts to net metering rates, charging NEM customers more each year;[39]
- Minnesota, where the Public Utilities Commission directed Xcel Energy to file a virtual power plant pilot by March 1, 2027 to test how aggregated customer-owned rooftop solar, residential storage and flexible loads can provide grid services, with specific provisions for low-income customers, renters, and multifamily residents;[40]
- North Carolina, where H.B. 589 of 2023 began the transition off of NEM, moving customers to time-of-use rates and cutting export credits to the utility's avoided cost rate.[41]

This report draws on these examples and others in the sections that follow.

Washington's reassessment of its distributed solar and storage compensation framework is occurring at a moment when the body of evidence on what works, and what doesn't, is more robust than it has ever been. The analytical frameworks, valuation methodologies, and policy mechanism designs developed and tested in other states provide a substantial empirical foundation on which Washington can build a rigorous and durable approach.

The state-level experiences currently documented provide the primary empirical foundation for this report's analysis of benefit quantification methodologies and policy mechanism design. The states whose programs and proceedings are examined in subsequent sections include California, New

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[34] South Carolina Public Service Commission. (2026, June 11). *Application of Dominion Energy S.C., Inc. for Authority to Adjust & Increase Its Retail Electric Rates & Charges, Docket No. 2025-325-E, Commission Directive*. https://dms.psc.sc.gov/Attachments/Matter/133ecdca-584b-4dc0-b2ab-cc410136379e

[35] Arkansas General Assembly. (2023). *Arkansas Act 278, 2023 Ark. Acts 278*. https://www.arkleg.state.ar.us/Home/FTPDocument?path=%2FACTS%2F2023R%2FPublic%2FACT278.pdf

[36] Connecticut General Assembly. (2026). *An Act Concerning Renewable Power Generation, 2026 Conn. Pub. Acts 127 (Reg. Sess. 2026)*. https://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&which_year=2026&bill_num=5340

[37] Maryland General Assembly. (2026). *Utility RELIEF (Reducing Energy Load Inflation for Everyday Families) Act, ch. 353, 2026 Md. Laws*. https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/HB1532?ys=2026RS

[38] Hawaii Green Infrastructure Authority. (n.d.). *Save on Your Energy Bill: Programs for Hawai'i Households*. https://gems.hawaii.gov/save-on-your-energy-bill-programs-for-hawaii-households/

[39] Vermont Public Utilities Commission. (2026). *2026 Biennial Report*. https://puc.vermont.gov/sites/psbnew/files/documents/2026-biennial-final.pdf

[40] Minnesota Public Utilities Commission. (2026). *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, Docket No. E002/M-25-142 (decided July 30, 2026)

[41] North Carolina General Assembly, (2017) *House Bill 589: Competitive Energy Solutions for North Carolina*. https://www.ncleg.gov/Sessions/2017/Bills/House/PDF/H589v5.pdf

York, Massachusetts, Minnesota, Texas (Austin Energy), Nevada, South Carolina, Arkansas, Connecticut, Maryland, and New Hampshire, among others. These jurisdictions collectively represent the range of regulatory structures (investor-owned utility regulation, municipal utilities, restructured markets), geographic and load characteristics, renewable resource profiles, and policy design philosophies that may help inform Washington's discussions.

However, several features of Washington's energy system and policy context are unique and warrant particular attention when applying out-of-state findings. First, hydroelectric generation supplies the majority of Washington's electricity, creating potential interactions between distributed solar and storage deployment and hydropower operations, including ramping requirements and seasonal dispatch patterns, that are largely absent from the experience of states that rely primarily on thermal generation. Second, Washington's high proportion of electric end-use services (relative to states with greater natural gas penetration of space heating and cooking) means that electricity rate increases have comparatively larger impacts on household energy burdens, making the distributional consequences of rate design choices particularly salient from an equity standpoint. Third, the suite of CETA, CCA, and HEAL Act obligations described in Section II creates a statutory policy environment that is more integrated and more explicitly equity-focused than that of most states, shaping the criteria against which policy mechanism design must be evaluated.

These Washington-specific factors are incorporated throughout the analysis that follows and, where relevant, are used to assess the transferability of findings from other jurisdictions.

IV. RESEARCH APPROACH AND METHODS

This work was organized around an eight-step methodological approach designed to move systematically from the identification of potential value streams to the characterization of policy mechanisms capable of realizing them. The steps are summarized here, the findings associated with each are developed in detail in the sections that follow, and a glossary of terms used can be found in Appendix A.

Step 1: Selected a representative subset of benefit and cost factors from the comprehensive taxonomy developed in the Interim Report, which catalogued more than 60 potential impact categories spanning generation, transmission, distribution, host customer, and societal dimensions (Appendix B). The objective was not exhaustive coverage but methodological breadth, a set of factors sufficient to exercise the full range of analytical approaches the project would need to develop and demonstrate. The candidate list was cross-referenced against two external benchmarks: the National Standard Practice Manual (NSPM)[42] for benefit-cost analyses of distributed energy resources, and a prior value-of-solar analysis conducted for Washington by the consulting firm Energy and Environmental Economics (E3).[43, 44] (Appendix C.) Tables 1 and 2 summarize the selected benefit and cost factors.

The cross-reference with the NSPM was used to ensure this report was using a recognized taxonomic approach, including key categories of distributed energy resource value, while also identifying gaps in areas including non-energy impacts, fuel price risk mitigation, and program administrative costs. Compared to E3's prior Washington analysis, the Interim Report offered a broader assessment, particularly in its treatment of distribution system factors, societal impacts, and host customer benefits beyond simple bill savings. This review is summarized in Appendix C and F.

The research team then organized factors along two dimensions. Factors were grouped into five major categories (generation, transmission, distribution, host customer, and societal) to ensure that the final selection would span the full range of categories. Each factor was then characterized along two analytical axes: its potential magnitude in the Washington context (i.e., how large could the impact realistically be, given Washington's load profile, resource mix, and regulatory environment?) and its analytical tractability (i.e., how well-established are existing quantification methodologies, and how data-intensive would implementation be). This characterization provided a working map of the trade-offs involved in any particular selection.

The project's Oversight Committee (OC) provided guidance on selecting a representative set of factors—one that would exercise the full methodological range of the project rather than clustering in familiar or easily quantifiable territory. Committee input produced strong consensus around several inclusions and helped clarify appropriate exclusions from the representative set at this

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[42] National Association of State Energy Officials. (2026). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources.* https://naseo.org/nesp/nspm
[43] Energy & Environmental Economics (E3). (n.d.) *About E3*, https://www.ethree.com/about/overview/
[44] Energy & Environmental Economics (E3). (2023, December 21) *Benefits and Costs of Net Energy Metering in Washington.* https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefits-and-Costs-of-Net-Energy-Metering-in-Washington_2023-12-21.pdf

stage. While important, many involved methodological complexity that exceeded this project's scope. See Appendix I for the rationale for their exclusion in this report.

Box 3. Terminology note: "avoided costs"

Throughout this document, "avoided costs" refers to utility system costs -- generation, transmission, distribution, or other infrastructure investments -- that a utility does not have to incur because a distributed resource (e.g., DERs, efficiency, demand response) serves that need instead. These costs are not eliminated from the system; they are shifted away from the utility and its ratepayers to another party -- typically the customer or third-party developer who owns and pays for the asset providing the service. From the utility's and ratepayers' perspective, these costs are avoided altogether, since that expense no longer appears in the utility's revenue requirement or rate base. From a system-wide perspective, however, the cost has not disappeared — it has simply moved to whoever financed the asset delivering the benefit. Unless otherwise noted, this document uses "avoided costs" in the ratepayer-savings sense: costs the utility (and by extension, ratepayers) no longer has to pay.

Eight benefit factors and two cost factors were selected. The benefit factors--avoided energy costs, avoided bulk capacity costs, avoided distribution capacity costs, market price impacts, host customer resilience, hydropower ramping interactions, improved economic wellbeing (distributional impacts), and job creation and economic development--span all five major system categories and include both well-established quantitative factors and analytically novel territory. The two cost factors--increased bulk capacity and distribution capacity costs--represent the most significant and least-disputed categories of increased cost attributable to distributed energy resource deployment. Moreover, these cost factors are also potentially benefit factors depending on the context.

Table 1. System Categories and Benefit Factors Relevant to Washington State

System Category	Selected Benefit Factors	Description
Generation (Bulk Power)	Avoided energy costs	Reflects costs a utility avoids paying to generate or purchase electricity because a distributed energy source supplies that energy instead
	Avoided bulk capacity costs	Reflects costs a utility avoids having to spend on building or producing new large-scale (bulk) generation, transmission, or capacity resources
	Market price impacts	Change in wholesale electricity prices caused by adding distributed energy resource output to the grid
	Hydropower ramping interactions	Specific to WA - reduction in ramping of hydropower generation resources up or down to balance supply and demand, which can cause positive or negative environmental impact depending on many factors

Distribution	Avoided distribution capacity costs	Costs utility avoids spending on upgrading or expanding local distribution system infrastructure because of distributed energy resources
Host Customer	Host customer resilience Economic wellbeing (distributional impacts)	Value a distributed energy resource provides to a specific customer who owns/hosts the system by maintaining power availability during grid outages How the benefits of distributed energy resources programs are distributed across different customer groups
Societal	Job creation and economic development	Broader economic and equity impacts beyond utility system accounting that includes local employment, business activity, and broader economic effects tied to the solar and storage industry

Table 2. System Categories and System Cost Factors Relevant to Washington State

System Category	Selected Cost Factors [45] [46]	Description
Generation (Bulk Power)	Increased bulk capacity costs	Costs that include integration, balancing and reserve requirements when distributed energy resources do not align with system peak demand
Distribution	Increased distribution capacity costs	Costs that include interconnection, grid upgrades, and protection system modifications on the local distribution infrastructure

Step 2: Conducted a systematic survey of the academic and regulatory literature and documented U.S. state experience to identify current methods for calculating the value of each selected factor. This literature review, summarized in Appendix D, formed the evidentiary basis for the benefit characterization presented in subsequent sections.

Step 3: Analyzed the four primary policy mechanisms through which BTM solar and storage are deployed and directed across U.S. jurisdictions: 1) retail rate design, 2) grid services tariffs, 3) utility procurements, and 4) deployment incentives. These mechanisms, defined and analyzed in

[45] In this report, the cost of installation is not a cost factor because the cost of installation is a private cost not borne by ratepayers. Per unit of energy, rooftop solar costs more to install than utility scale solar, and more than Washington's existing hydropower. This report looks at the utility and ratepayer perspective, and the customer bears the installed costs of their own systems, not the utility. For a full comparison of tests for resource costs, see Appendix D.

[46] *Note:* Table 2 lists the system cost factors, meaning the costs that distributed solar and storage can impose on the grid. Payments made through the policy mechanisms themselves, such as export compensation, grid services payments, procurement payment contracts, and deployment incentives, are treated separately as mechanism costs and are characterized for each mechanism in Section V and Section IX.

Section V of this report, are the primary levers available to Washington policymakers for realizing the potential value streams.

Step 4: Identified documented examples from other states in which each selected benefit factor was quantified in connection with the implementation of one or more of the four policy mechanisms. For each example, the team identified the analytical method, formula, or tool employed, the data inputs required, and the resulting quantitative values where available.

Step 5: Developed a qualitative characterization of how effectively each policy mechanism tends to realize each benefit factor. Solar-only and solar-plus-storage configurations were analyzed separately given the fundamental operational differences between these resource types and whether or not other states had been able to consider the technological differences in their own analyses.

Step 6: Conducted a parallel characterization of the costs, including the two identified cost factors and the mechanism costs, using per-unit metrics (cost per kilowatt of solar deployed; cost per kilowatt-hour of storage capacity deployed) to enable cross-mechanism comparison.

Step 7: Applied an equity lens to these findings, examining for each factor and mechanism how benefits and costs are distributed across income levels and communities, and identifying existing programs and emerging best practices that address distributional concerns.

Step 8: Synthesized findings to inform policy decision-making, including the identification of principal conclusions regarding mechanism design, portfolio approaches, and the conditions under which specific mechanisms are most likely to achieve cost-effective benefit realization.

How This Project Addresses Cost Shift

Cost shift is one of the most contested terms in distributed energy policy, and this report is transparent about the limits of what it can resolve. In utility regulation and energy policy, a cost shift occurs when one group of customers does not pay the full costs attributed to the electric system, and those costs are instead recovered from other customers through rates.

This report acknowledges that debate but does not resolve it, because the core disagreement, how large the shift is and how to measure it, is a contested empirical and methodological question that no single study can settle. The end of Section V discusses the debate briefly and Appendix E reviews the relevant peer-reviewed literature on both sides, including the limited body of Washington- and Pacific Northwest-specific academic research bearing on the question. What this report can do is reframe the question in terms that Washington's statutory framework already answers: not whether cost shift exists, but how policy mechanisms can be designed to minimize it while still meeting the state's deployment and equity goals.

V. PRIMARY POLICY MECHANISMS FOR REALIZING THE VALUE OF DISTRIBUTED SOLAR AND STORAGE

The value that ratepayers and residents realize from distributed solar and storage resources is not an automatic function of the hardware deployed. It is a function of the policy mechanisms that govern how those resources are compensated, dispatched, and integrated into the broader electricity system. A solar-plus-storage system capable of reading peak demand on the grid, maintaining stable and reliable power, and providing backup power during outages will realize those benefits only to the extent that applicable compensation structures create incentives for investors to invest and operators to deploy and operate the hardware in ways that produce them.

The four mechanisms explored here–retail rate design, grid services tariffs, utility procurements, and deployment incentives–are not mutually exclusive. Any given behind-the-meter (BTM) installation may be subject to multiple mechanisms simultaneously: a customer installs a solar-plus-storage system because an incentive program made the investment economically attractive; the system's daily dispatch behavior is governed by the customer's retail rate structure and resilience needs; the battery may be enrolled in a grid services program that dispatches it during peak demand events; and the aggregation of many such installations may be the subject of a utility procurement contract.

To offer a complete picture, policy analysis needs to avoid examining any single mechanism in isolation. The value of distributed solar and storage, and the cost-effectiveness of realizing it, is a portfolio-level question that depends on how the mechanisms interact and reinforce one another.[47] A policy mechanism can be evaluated based on its individual effects conditional on the status of other mechanisms, and based on how it interacts with other policy mechanisms. For example, the combination of time-of-use (TOU) rates and net energy metering (NEM) compensation levels can shape investment incentives in different directions. High daytime TOU rates combined with high NEM export values tend to favor larger solar installations with limited battery deployment, whereas high evening TOU rates combined with lower NEM export values can shift incentives toward greater battery adoption and relatively less solar capacity.

These interactions extend beyond primary economic outcomes to influence non-energy impacts such as resilience: a rate design and incentive combination that favors larger battery capacity (e.g., high evening TOU rates paired with low NEM export values) also increases the backup power duration available to the customer during outages, while a grid services tariff that requires the utility to dispatch the battery during peak events may leave less reserved capacity on hand when an outage actually occurs, so the same mechanisms that shape investment and dispatch decisions also determine how much resilience value a household or community ultimately realizes.

When rate structures make solar and storage systems economically attractive under normal operating conditions, the incremental cost of adding resilience features–such as microgrid islanding capability–becomes relatively small. By contrast, when existing policy mechanisms do

[47] National Association of Regulatory Utility Commissioners & National Association of State Energy Officials. (2024, July). *Aggregated Distributed Energy Resources in 2024: The Fundamentals*. https://www.naruc.org/our-work/naruc-naseo-aggregated-der-report

not support solar and storage deployment, resilience investments must be justified independently, increasing the overall cost because generation, storage, and islanding capabilities must all be funded within a dedicated resilience investment.

This section describes the four primary policy mechanisms through which distributed solar and storage have been deployed and directed across U.S. jurisdictions; analyzes the regulatory processes through which each is established; and characterizes the strengths, limitations, and cost structures associated with each.

Retail Rate Design

Mechanism Description and Operation[48]

Retail rate design is the foundational policy lever through which regulators shape the financial economics of BTM solar and storage adoption and operation. Electric utilities are authorized to recover the incurred costs of generating and delivering electricity through rates approved by the applicable regulatory authority. In Washington, those are the Washington Utilities and Transportation Commission (UTC) for investor-owned utilities and the governing boards of public utility districts and municipal utilities for the state's publicly owned utilities. Within this cost-recovery framework, regulators may design rate structures that create financial incentives, or disincentives, for specific customer behaviors, including the installation and operation of distributed energy resources.

The central instrument of retail rate design for distributed solar is the export compensation structure, which has two distinct components: the netting interval over which exports are matched against consumption, and the credit rate applied to net exports.

Under traditional NEM, exports are netted against consumption over the full billing period, and the credit is set at the customer's full retail rate, which bundles generation, transmission, distribution, and fixed cost recovery components into a single volumetric price. NEM is distinctive in that, by definition, the customer is credited at the full volumetric retail rate for any electricity exported within a given billing period.[49]

Under a net billing tariff, the netting interval shrinks dramatically. Rather than netting over the monthly billing cycle, exports are matched against consumption on a near-instantaneous basis. The National Laboratory of the Rockies (NLR) (until 2025 called the National Renewable Energy Laboratory (NREL)) defines net billing as a metering and billing arrangement where the netting frequency is less than the billing cycle, and notes that in practice such arrangements nearly always use an instantaneous netting frequency.[50] California's implementation, formally called the Net

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[48] A useful resource for an updated bibliography on rate design and distributed energy resources is: Lawrence Berkeley National Laboratory, Electricity Markets & Policy Group. (n.d.). *Publications: Rate Design, Regulations, and Programs*. https://emp.lbl.gov/research-areas/rate-design-policy-and-programs

[49] Zinaman, Eric, et al. (2017, October). *Grid-Connected Distributed Generation: Compensation Mechanism Basics* (NREL/BR-6A20-68469). National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy18osti/68469.pdf

[50] The U.S. Department of Energy operates a network of national laboratories, several of which are central to energy and electric research.

Billing Tariff, illustrates this: it replaced NEM 2.0 in April 2023, with export credits set using the CPUC's Avoided Cost Calculator rather than the retail rate.[51] Under this structure, storage-mediated dispatch during higher-value evening periods becomes far more advantageous, since energy exported is worth less than energy imported, making it advantageous to maximize self-consumption and pair solar with storage.[52, 53, 54] Under a value-of-solar tariff, the export credit is set at a rate intended to reflect the calculated value of the exported energy to the utility system, independent of the netting interval used.[55] This calculation typically incorporates avoided energy generation costs, reduced grid congestion, and environmental benefits, distinguishing it from a feed-in tariff, which compensates generation at an administratively set value but is designed explicitly to incentivize adoption of distributed generation rather than to reflect system value.[56]

It's important to note that "net billing" describes the netting interval structure, not necessarily the credit rate itself. Net billing tariffs vary in how their credit rates are set: many are at or close to avoided cost–as in California, where credits fell from near-retail rates of roughly $0.30/kWh under NEM 2.0 to an average of about $0.05 to $0.08 per kWh under NEM 3.0. But many others fall somewhere between retail rate and avoided cost, as seen in states like Arizona, Nevada, and Indiana, which have moved to net billing structures with below-retail export rates, or Texas's deregulated market, where buyback rates range from a few cents per kWh up to retail-matched, depending on the plan. The netting interval and the credit rate are separate design choices that can, in principle, be mixed and matched.[57, 58]

Where net billing credit rates are set at avoided cost, and value-of-solar credit rates are set at the calculated value of exported energy, the two can converge in theory. In practice, the differences between them are largely a function of methodology and how frequently the underlying calculations are updated.

Beyond export compensation, retail rate design encompasses several structural features that are particularly relevant for solar-plus-storage economics:

- **Time-of-use (TOU)** rates differentiate the per-kilowatt-hour price of electricity by time of day and, in some cases, season. When TOU rates are in effect, a customer with battery storage has a direct financial incentive to charge the battery during off-peak hours (when electricity is cheapest) and discharge it during on-peak hours (when electricity is most expensive), thereby reducing the customer's net consumption during high-cost periods.

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[51] California Public Utilities Commission. (2024, October 2). *2024 Distributed Energy Resources Avoided Cost Calculator Documentation (Version 1b).* https://www.cpuc.ca.gov/dercosteffectiveness
[52] Ibid.
[53] OhmSnap Editorial. (2026, April 7). *California NEM 3.0 (Net Billing Tariff): The Complete Guide for 2026.* https://www.ohmsnap.com/nem-3-guide
[54] Wu, Bob. (2025, September 4; updated April 24, 2026). *Net Metering vs. Net Billing: Impacts on PV Interconnection.* Anern. https://www.anernstore.com/blogs/costs-incentives-policy/net-metering-vs-net-billing-pv
[55] Austin Energy. (2026). *Value of Solar Rate.* https://austinenergy.com/rates/residential-rates/value-of-solar-rate
[56] Woolf, Tim, et al. (2016, November 10). *Show Me the Numbers: A Framework for Balanced Distributed Solar Policies.* Prepared for Consumers Union. Synapse Energy Economics, Inc. https://www.synapse-energy.com/sites/default/files/Show-Me-the-Numbers-16-058_0.pdf
[57] California Energy Initiative. (2026, July 13). *NEM 3.0 Explained: What Changed and What It Means for Your California Bill (2026).* https://cainitiative.com/blog/nem-3-0-explained-what-changed-california-bill
[58] ROI Solar. (n.d.). *Net Metering 101.* https://roi.solar/residential/articles/net-metering-101/

TOU rates also make it possible for export compensation to reflect time-differentiated grid value, crediting on-peak exports at higher rates than off-peak exports.

• **Demand charges**, applicable primarily to commercial and industrial customers, impose a cost based on the customer's maximum power draw during a defined billing interval (typically the highest 15-minute average over the billing month). Battery storage can substantially reduce demand charges by discharging during intervals that would otherwise set the peak demand measurement, providing a bill-savings driver independent of and additive to energy arbitrage (buying low/selling high) value.

• **Dedicated storage tariffs**, adopted by a small number of utilities, are rate structures specifically designed around the operational characteristics of battery energy storage systems. These tariffs may offer enhanced compensation for discharge during defined critical grid periods, guaranteed credits for on-site consumption of stored energy, or performance-based adders tied to grid event response. In California, Pacific Gas and Electric's E-ELEC schedule is a representative example of a storage-optimized residential rate structure.[59]

• **Fixed charges** (flat fees that do not vary with usage and are used to recover the costs of maintaining the grid connection, metering, and customer service) and **non-bypassable charges** (mandatory per-kilowatt-hour charges that fund shared systems costs such as public purpose programs, low-income assistance, and legacy system costs) both limit how much of a customer's bill can be offset by self-generation and storage, but they do so in different ways. Fixed charges set a minimum bill that customers pay regardless of how much electricity they consume or export. Non-bypassable charges, by contrast, reduce the cost shift when they are assessed on every kilowatt-hour a customer imports from the grid and excluded from the credit for exported energy. Each affects the economics of solar-plus-storage by determining the minimum bill obligation that customers face regardless of their net energy position.

Regulatory Process

Retail rates for Washington state's three investor-owned electric utilities are established through formal proceedings before the UTC, typically through general rate cases or targeted rulemaking proceedings. Rate cases are adversarial proceedings in which the utility files a proposed rate schedule, intervening parties (including the UTC staff, the Attorney General's office representing ratepayers, and other interested stakeholders) submit testimony and engage in discovery, and the Commission issues an order approving, modifying, or rejecting the proposed rates. This process is resource-intensive, typically spanning many months, and is subject to significant legal and procedural constraints that limit the speed with which rate structures can be updated in response to changing market conditions or technology costs.

[59] Pacific Gas and Electric Company. (n.d.). *Schedule E-ELEC: Residential Time-of-Use Service for Generation-Metered Customers with Electric Vehicles, Battery Storage, or Electric Heat Pump Space or Water Heating.* Cal. P.U.C. Sheet No. 61116-E. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-ELEC.pdf

For publicly owned utilities in Washington, which serve approximately 55% of the state's residential customers and provide about one half of its electric load, rate-setting authority rests with the utility's governing board (the board of commissioners for a public utility district, or the city council for a municipal utility).[60] These utilities are not subject to UTC jurisdiction over rate design, though they remain subject to the NEM statute and other state energy laws. The diversity of regulatory structures across Washington's utility landscape, spanning one large investor-owned utility, multiple smaller investor-owned utilities, several large public utility districts, numerous municipal utilities, and several rural utility cooperatives, has important implications for the uniformity and pace of distributed energy policy implementation across the state. Appendix G lists the range of utilities in Washington State.

Key regulatory debates in retail rate design proceedings for distributed energy resources include: the appropriate level of export compensation (full retail rate, avoided cost, or an intermediate value-of-solar rate); to what extent NEM participants should be assessed fixed grid access charges to address cost-allocation concerns; and how to structure time-varying rates in ways that convey accurate price signals without creating undue complexity or access barriers for residential customers.

Strengths and Limitations

Retail rate design has several structural advantages as a policy mechanism for distributed solar and storage. It is broadly scalable: once a rate structure is approved, it applies automatically to all eligible customers who install qualifying systems, without requiring individual contracting, procurement cycles, or program enrollment procedures. It is also durable: an approved rate structure remains in effect until modified through a subsequent regulatory proceeding, providing multi-year market certainty for installers and investors. And it is comprehensive in its reach: because every BTM solar or storage customer is subject to the applicable retail rate, rate design affects both the deployment decision (does the investment make economic sense?) and the operational behavior (how should the system be dispatched to maximize customer savings?).

The principal limitation of retail rate design as a mechanism for realizing distributed energy resource value is its coarseness. A retail rate, even a well-designed TOU rate, cannot compensate solar-plus-storage systems for the full array of grid services they may be capable of providing—including frequency regulation, voltage support, and locational capacity relief—because most of these services require dispatch control and measurement capabilities that are beyond the scope of standard retail metering and billing systems. Retail rates also cannot easily differentiate compensation based on the locational value of a specific installation: a battery installed at a distribution feeder constrained by peak load receives the same rate signals as one installed at a feeder with substantial reserve capacity, even though the former provides substantially greater system value. Furthermore, rate cases are time-consuming and contested proceedings, which limits the frequency with which rate structures can be updated to reflect evolving system conditions, technology costs, or policy priorities.

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[60]Washington State University Energy Program. (2026). *Net Metering*. https://energy.wsu.edu/our-work/renewable-energy/net-metering/

An important consequence of retail rate design–and a complication for using retail rates as a benchmark in cost-effectiveness analysis–is the potential for cost shifting. Where NEM or other export compensation structures credit exported energy at rates that exceed the utility's actual avoided cost, the resulting revenue shortfall is recovered through rates charged to all customers, including those who have not installed solar. This is not necessarily a defect in rate design itself: rate design is a flexible policy instrument, and setting export compensation above avoided cost can be a deliberate choice, for example to help a distributed solar installation recover its costs and make the investment worthwhile to the host, particularly in the absence of other incentive programs. But whatever its policy rationale, the effect is the same–non-adopting customers bear a portion of the cost of adopters' investments–and this cost shift can be regressive in its distributional effects if, as has often been the case, solar adopters are concentrated in higher-income households.

For cost-effectiveness analysis specifically, this issue matters because retail rates often recover costs beyond the utility's avoided costs and therefore are not, by themselves, a direct measure of economic value. When export compensation is tied to retail rates and includes additional policy objectives, the divergence between compensation and avoided costs can become even greater, complicating assessments of cost-effectiveness that rely on retail rates as a benchmark. This tradeoff is not inherent to NEM successor design. It arises specifically when adoption incentives are embedded in the export compensation rate itself. Regulators and policymakers who keep adoption incentives inside retail rate design introduce a constraint. Maintaining adoption incentives sufficient to drive continued deployment, including deployment needed to achieve Washington State's decarbonization goals, can compete against the objective of limiting cost shifts among customers. This occurs because the two objectives are mechanically linked through the same rate. Separating adoption incentives into a distinct, non-rate based program (e.g., deployment incentive, grid services tariff, or utility procurement), removes that linkage. Rates can then be set to track avoided cost and eliminate cost shift by construction, while deployment incentives are pursued independently through a separate funding mechanism.

Cost Structure

For this report, the relevant cost of retail rate design is the cost shift to non-participating customers. A cost shift occurs when customers are paid more for exported electricity than the utility avoids in direct system costs, and the difference is recovered from other ratepayers. The size of the cost shift depends on the difference between the export compensation rate and the utility's avoided costs, as well as the amount of electricity exported. Analyses conducted in Nevada, South Carolina, New York, and Arkansas have produced cost shift estimates ranging from zero (in Arkansas) to approximately $0.08 per kilowatt-hour of exported energy to non-participating customers (in Nevada for existing NEM installations).[61, 62] Importantly, the cost shift does not reflect the costs of the distributed resources themselves; it reflects the degree to which the rate design mechanism over- or under-compensates those resources relative to their actual system

[61] Price, S. et al. (2016). *Nevada Net Energy Metering Impacts Evaluation: 2016 Update*. San Francisco, CA: Energy and Environmental Economics, Inc. Prepared for the Public Utilities Commission of Nevada, Docket No. 2016-8. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf

[62] Arkansas Net-Metering Working Group. (2017, September 15). *Joint Report and Recommendations of the Net-Metering Working Group*, Docket No. 16-027-R (Doc. 228). Arkansas Public Service Commission. http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf

value. A rate design in which export compensation precisely equals avoided cost produces a cost shift of zero by construction.

The direct system costs associated with distributed solar and storage deployment–increased interconnection costs, potential distribution infrastructure upgrades, and changes in bulk system operations attributable to distributed generation–are addressed separately as cost factors in the benefit-cost analysis framework (Section IX) and are not treated here as mechanism costs.

Grid Services Tariffs

Mechanism Description and Operation

Grid services tariffs--also referred to as grid services programs or performance-based compensation programs--are rate schedules that compensate distributed energy resource owners specifically for the grid services their systems provide, rather than (or in addition to) the energy value of their generation or self-consumption. Where retail rate design operates primarily through price signals embedded in a customer's standard electricity bill, grid services tariffs establish a separate, explicit compensation framework for defined grid service outputs--such as peak demand reduction, voltage support, or frequency regulation--that are not adequately captured in volumetric energy rates.[63]

These programs can vary along several structural dimensions that are often left unstated or implied but are important to specify for clarity. One key dimension is operational control. Some programs are utility-directed, where the utility dispatches the customer's resource directly to deliver the contracted service. Other programs are customer-directed, in which the customer or a third-party aggregator retains dispatch authority and responds to a signal, incentive, or performance obligation on its own terms. Some programs blend the two, for example granting the utility dispatch rights within limits set by the customer. This discussion addresses grid services tariffs broadly and is intended to encompass all three arrangements, but the distinction matters because it affects reliability of the service, the customer's operational burden, and the allocation of performance risk.

A second dimension is the underlying ownership and contractual structure. This covers who owns the distributed energy resource (DER), whether the customer, a third-party developer, or the utility itself, who bears the cost of installation and maintenance, and who pays whom for the service delivered. In some arrangements the utility compensates the resource owner directly for service delivered. In other cases an aggregator or third party contracts with the customer, aggregates multiple resources, and is in turn compensated by the utility, or increasingly, by a wholesale market operator.[64] These ownership and payment relationships are frequently implicit in program design, but they should be made explicit, as they determine which party bears technology,

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[63] National Association of Regulatory Utility Commissioners (NARUC) & National Association of State Energy Officials. (2024, July). *Aggregated Distributed Energy Resources in 2024: The Fundamentals* https://www.naseo.org/data/sites/1/documents/publications/NARUC_ADER_Fundamentals_FinalUpdated.pdf

[64] Lawrence Berkeley National Laboratory. (2025, January) *State Regulatory Opportunities to Advance Distributed Energy Resource Aggregations in Wholesale Markets*. https://emp.lbl.gov/publications/state-regulatory-opportunities

performance, and credit risks, and they shape the incentives each party has to maintain and optimize the resource over time.

The defining operational characteristics of grid services programs are:

- **Performance-based compensation**: Payments are triggered by actual, measured performance during defined grid service events (e.g., a battery discharging during a utility-declared peak demand period) rather than by the mere installation of a qualifying asset. This performance-linkage ensures that compensation is tied to demonstrated grid value rather than to the theoretical capabilities of installed hardware.

- **Open enrollment:** Unlike competitive procurement processes, grid services programs are typically available for continuous enrollment by eligible resources. Distributed energy resource owners can apply, qualify, and begin earning payments without waiting for a solicitation window or participating in a competitive selection process.

- **Defined dispatch protocols**: Program administrators issue dispatch signals (day-ahead or same-day notifications) directing enrolled resources to charge, discharge, or curtail in response to specified grid conditions. The precision and frequency of dispatch signals varies by program design and by the grid service being targeted.

- **Optional aggregation:** Some programs permit individual distributed energy resource owners to enroll directly; others require participation through a third-party aggregator that manages the operational coordination and settlement functions on behalf of multiple small resources. Aggregation reduces per-resource transaction costs but introduces an intermediary layer whose compensation structure and contractual obligations must be designed carefully to preserve appropriate incentives.

Compensation structures under grid services programs vary across jurisdictions. Some programs pay a flat rate per kilowatt-hour of energy delivered during dispatched events. Others pay a capacity reservation fee per enrolled kilowatt of qualified capacity, plus a performance payment per kilowatt-hour dispatched. Hybrid structures combine upfront capacity payments with performance-based energy payments and may include penalties for resources that fail to respond to dispatch signals within specified tolerance limits. Current best practice, reflected in programs such as Massachusetts' ConnectedSolutions program[65] and Duke's PowerPair,[66] is to price compensation at or near the calculated value of the service being provided--effectively targeting a benefit-to-cost ratio of 1.0 from the ratepayer perspective.

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[65] Energy Toolbase. (2025, March 3, Updated March 6, 2026.). *Getting Optimal Value from Energy Storage with ConnectedSolutions in Massachusetts and Rhode Island*. https://www.energytoolbase.com/blog/energy-storage/maximizing-energy-savings-with-connectedsolutions-in-massachusetts-and-rhode-island/

[66] Duke Energy. (2024, April 4). *Duke Energy to Implement New PowerPair Pilot Program for Pairing Home Solar Installations with Battery Energy Storage* [Press release]. https://news.duke-energy.com/releases/duke-energy-to-implement-new-powerpair-pilot-program-for-pairing-home-solar-installations-with-battery-energy-storage

Regulatory Process

Grid services tariffs are established through regulatory filings with the applicable commission or utility governing authority, typically in conjunction with or following rate cases that address the broader retail rate structure. In jurisdictions with investor-owned utilities, grid services programs may be proposed by the utility, by the commission's staff, or through legislative direction. These programs are subject to the same evidentiary processes and contested proceedings that govern retail rate changes. Program design details–including eligibility criteria, performance measurement protocols, compensation rates, enrollment caps, and program duration–are typically specified in the tariff schedule filed with the commission.

A significant regulatory consideration in the design of grid services programs is the interface between utility retail tariffs and federal wholesale market participation. For states in which utilities are connected to regional wholesale markets (utilities may participate voluntarily in Washington State), there are different opportunities for DER owners. Such owners enrolled in state-level grid services programs can participate in wholesale markets–stacking revenue streams, improving the overall economics of storage deployment. The appropriate allocation of compensation between utility tariff payments and wholesale market revenues requires regulatory coordination and careful program design to avoid double-counting benefits or creating perverse dispatch incentives.

Strengths and Limitations

The principal strength of grid services tariffs is the precision of the incentive they create. By compensating distributed energy resources specifically for the grid services they provide, measured at the time and location they are provided, these programs can influence when and how enrolled assets operate (for example, when a battery charges or discharges, when a smart thermostat or water heater reduces load, or how a solar inverter manages its output and voltage) and steer that activity toward the highest-value uses with a degree of accuracy that volumetric retail rates cannot achieve. Performance-based structures also ensure that ratepayer compensation is tied directly to demonstrated output, reducing the risk of paying for services that are not actually delivered.

For distributed solar-plus-storage systems, grid services tariffs provide a compensation pathway for value streams that are not captured in the retail rate structure: locational capacity relief at specific points on the distribution system; dispatch during utility-declared peak events that may or may not coincide with the on-peak periods in a TOU rate; and response to grid operator signals that reflect real-time system conditions. Because these services are compensated separately from the retail bill, grid services programs can be combined with retail rate design and deployment incentives to create a stacked compensation structure in which each mechanism targets a distinct category of value.

Grid services programs also have meaningful limitations. Program budgets are often capped by regulatory order or legislative appropriation, creating the possibility of enrollment waitlists that limit program scale and introduce market uncertainty for prospective participants. Compensation rates set administratively may not track the true market value of the targeted services over time, particularly as distributed energy resource penetration grows and the marginal value of additional capacity or demand response changes. The design of dispatch signals and performance

measurement protocols must be carefully calibrated. Dispatch events that are too frequent or too demanding may cause battery degradation that deters participation, while infrequent or poorly targeted dispatch may produce insufficient grid value to justify the program's administrative costs. Finally, as noted above, grid services compensation typically applies only to electricity exported to the grid; energy consumed on-site by the host customer is compensated (or not) through the applicable retail rate, meaning that grid services programs must be paired with appropriate retail rate structures to realize the full range of distributed energy resource benefits.

Cost Structure

The mechanism cost of a grid services tariff or program is the compensation paid by the associated utility to enrolled resources for their performance of the specified services. Current best practice, as noted above, prices this compensation at the calculated value of the service provided–that is, the dollar value of the ratepayer benefits attributable to the resource's dispatch. Where compensation is set equal to value, the benefit-to-cost ratio of the program is 1.0 by design: ratepayers pay exactly the value they receive, and the mechanism is cost-effective but not net-positive.

Grid services compensation that diverges from a resource's calculated value is itself a form of cost-shifting, distinct from but analogous to the cost-shifting discussed above in the retail rate context. Compensation set *above* calculated value shifts costs to ratepayers, who fund payments exceeding the actual system benefit provided. In theory, programs could instead be designed to compensate resources *below* their calculated value–shifting costs in the opposite direction, onto the host/participant–producing a benefit-to-cost ratio greater than 1.0 and generating net ratepayer benefits. None of the programs reviewed during this research adopted this below-value approach, likely because it would reduce program attractiveness to potential participants and might compromise enrollment objectives. As the market for distributed energy resource grid services matures and enrollment costs decline, the competitive dynamics of grid services program design may shift in ways that create opportunities for below-value compensation, and the ratepayer-favorable cost-shifting it implies.

Administrative costs, including program design, metering and verification infrastructure, dispatch system operations, and settlement processing, constitute an additional category of mechanism cost that should be incorporated into program cost-effectiveness evaluations. These costs vary substantially by program design (aggregated versus direct enrollment) and by the measurement and verification protocols required for the targeted grid services.

Utility Procurements

Mechanism Description and Operation

Utility procurements are competitive solicitation processes through which distribution utilities or, in restructured electricity markets, community choice aggregators and other load-serving entities, acquire grid services or capacity from aggregations of BTM energy resources. Because individual residential or small commercial distributed energy resource installations are too small to be administratively or contractually meaningful on a standalone basis, utility procurements for BTM resources are conducted with aggregators and virtual power plant (VPP) (See Box 4.) operators that

assemble portfolios of customer-sited assets and bid them into utility solicitations as single, coordinated grid resources.

Box 4. Virtual Power Plants

A virtual power plant (VPP) is a network of distributed energy resources, such as rooftop solar, battery storage, electric vehicles, smart thermostats, and demand-response-enabled appliances, that are aggregated and coordinated through software to function collectively like a single, dispatchable power plant. Rather than generating electricity from one centralized facility, a VPP draws on many small, customer-sited resources spread across the grid, using real-time communication and control systems to shift consumption, discharge stored energy, or reduce load in response to load needs.

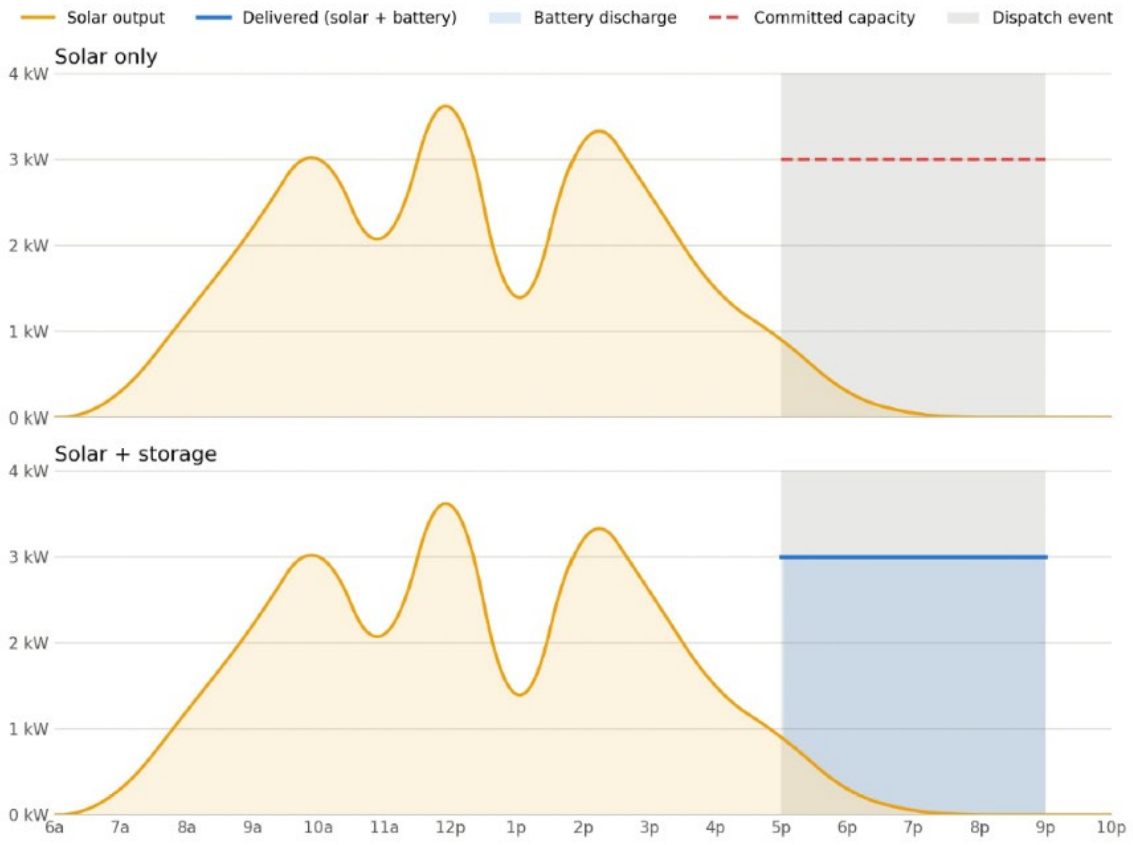
Utility procurements share the basic architecture of the grid services tariffs discussed above. Both structures compensate a third party for grid value delivered by customer-owned distributed assets, and both can be structured so that the customer, an aggregator, or the utility bears different pieces of installation, dispatch, and performance risk depending on program design. The two mechanisms diverge, however, along the same dimensions the prior section uses to characterize grid services tariffs. On operational control, utility procurements are, by design, utility-directed: power purchase agreements (PPAs) and service contracts obligate the aggregator to deliver dispatchable capacity on utility command during defined operating windows, leaving little room for the customer-directed or blended-control arrangements found in some grid services programs. On ownership and payment structure, utility procurements resemble the aggregator-intermediated grid services arrangements described above -- the utility pays the aggregator under contract, and the aggregator passes through a share of that revenue to enrolled customers -- but procurement compensation is set through competitive bid pricing rather than a standing tariff rate. That bid-based structure also filters the eligible resource mix more narrowly than grid services tariffs typically do. As such, procurement contracts require short-notice dispatchability where solar-only portfolios are generally not viable bidders and utility procurements function in practice as procurements of storage or solar-plus-storage capacity.

A fundamental characteristic of utility procurements for distributed energy resources is that utilities procure services, not assets. Procurement contracts do not typically involve utility ownership of the underlying distributed hardware; rather, they establish contractual obligations for the aggregator or VPP operator to deliver specified grid services (typically capacity, demand response, or local reliability services) during defined operating periods, at agreed compensation rates. This structure preserves customer ownership of the installed hardware while enabling the utility to count the aggregated resource toward its capacity or reliability obligations.

Because the grid services most commonly procured through utility RFP processes require dispatchability (the ability to respond to utility dispatch signals on short notice and with high reliability) solar-only BTM resources are generally not viable candidates for procurement contracts. Figure 1 provides a generic example of solar only vs solar-plus-storage dispatchability. Solar generation is, practically speaking, non-dispatchable: its output depends on irradiance conditions that cannot be controlled or reliably predicted at the sub-hourly intervals relevant to grid reliability events. As a result, the research team did not identify examples of utilities issuing procurement RFPs specifically targeting aggregations of solar-only BTM resources, and does not expect such

procurements to become a significant option going forward. Utility procurements for BTM resources are, in practice, procurements of storage or solar-plus-storage systems whose battery components can provide the dispatchable capacity and demand response that procurement contracts require.

Figure 1. Solar only versus solar-plus-storage dispatchability



The procurement process unfolds through several stages. The utility or regulatory body identifies a specific grid need: typically a local distribution capacity constraint, a transmission upgrade deferral opportunity, or a resource adequacy requirement identified in the utility's integrated resource plan or distribution system plan. An RFP is issued specifying the required capacity (in megawatts or megawatt-hours); the delivery location (which may be a specific feeder, substation zone, or system-wide); and the contract duration, performance requirements, and compensation structure. Aggregators respond with bids representing portfolios of enrolled customer distributed energy resource assets. Winning bidders execute power purchase agreements (PPAs) or service contracts committing them to deliver the procured grid services on utility command during defined operating windows.

Aggregators typically distribute a portion of the contract revenue to enrolled customers as an additional income stream layered on top of the customers' retail rate savings. Beyond direct bill

savings, this revenue-sharing also improves the payback economics of the underlying distributed assets–thermostats, batteries, EV chargers–making customer investment in them more attractive. That matters because the aggregator's ability to fulfill and scale its procurement contract depends on a large, responsive base of enrolled resources. The procurement contract thus doubles as a growth mechanism: contract revenue subsidizes asset adoption, which expands the aggregated resource pool, which in turn strengthens the aggregator's capacity to win and perform on future contracts.

Some well-known examples of utility procurement of DERs can be found in the procurement-style variations of non-wires alternatives (NWA) programs, of which Con Edison's Brooklyn-Queens Demand Management Program is the pioneering U.S. example. It represents a specific variant of utility procurement in which distributed energy resources, including storage, demand response, energy efficiency, and other non-traditional solutions, are procured competitively as an alternative to conventional capital investments in distribution infrastructure.[67] NWA procurements require the utility to demonstrate that the distributed resource solution can meet the identified grid need at lower total cost than the traditional infrastructure investment and to submit the NWA solution for regulatory approval as an alternative to the capital project.[68]

Regulatory Process

Utility procurement programs for distributed energy resources are subject to regulatory oversight in investor-owned utility jurisdictions, typically requiring commission approval of the program structure, the RFP design, and the resulting contracts before they can be implemented and before associated costs can be recovered in rates. Regulatory approval processes vary in complexity depending on the scale of the procurement, the novelty of the program structure, and the degree of precedent established in prior proceedings. In states with active DER procurement programs (e.g., California, New York, and Massachusetts) regulatory frameworks for utility procurement have evolved significantly over the past decade, and approval processes have become more streamlined as program designs have been refined and precedent has accumulated.

A distinctive regulatory feature of utility procurements relative to retail rate design is their location-specificity. While retail rates are established on a system-wide or customer-class basis and apply uniformly across a utility's service territory, procurement RFPs can be targeted to specific geographic areas or grid locations where distributed resource deployment would provide the greatest system value. This locational specificity is both a strength and a complexity: it allows procurement programs to direct distributed energy resource deployment to where it is most needed, but it requires more detailed distribution system modeling and planning data than is needed for system-wide rate design proceedings. In addition, procurement is a mechanism that enables a utility to acquire a resource. A single RFP-procured resource might then go on to provide multiple grid services once it is in place. Procurement's location-specificity is one lever for

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[67] Con Edison. (n.d) *Non-Wires Solutions*. https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions

[68] Lawrence Berkeley National Laboratory. (2021, February). *Locational Value of Distributed Energy Resources*. Prepared for the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

capturing value; grid services add a second, functional lever that procurement design alone doesn't fully address.

Strengths and Limitations

The principal competitive strength of utility procurements as a policy mechanism for distributed energy resources is their potential for net positive ratepayer value. Because procurements are conducted through competitive RFP processes, they create market conditions in which aggregators bid at the lowest compensation level that makes the contract economically viable for the distributed resource operators involved. If the competitive market functions effectively, the procurement process reveals the minimum cost at which the utility can acquire the targeted grid services. If that cost falls below the value of the avoided capital investment or reliability benefit, the ratepayers who fund the contract receive net positive value. As the market for distributed energy resource aggregation matures, the costs of customer acquisition, system integration, and dispatch operations are expected to decline, potentially improving the net value of procurement programs over time.

Utility procurements also offer the greatest degree of locational and temporal precision among the four primary mechanisms: RFPs can specify exactly where and when the procured capacity must be available, enabling utilities to target their distributed resource investments to the specific grid needs identified in their infrastructure plans. And because procurement contracts are typically five to ten years or more, they provide revenue certainty for aggregators and developers that facilitates project financing and reduces the risk premium embedded in compensation rates.

The limitations of utility procurements are largely transactional and structural. Each procurement cycle involves significant legal, contracting, and administrative overhead: RFP design, bid evaluation, contract negotiation, and regulatory approval each consume time and resources before any distributed energy resource is deployed. This transaction intensity limits the speed at which procurement programs can scale and makes them poorly suited as the primary driver of broad-based distributed solar and storage adoption across a utility's service territory. Customer acquisition and enrollment costs for aggregators remain high relative to the per-installation revenues from small residential systems. This can create economic incentives that favor larger commercial and industrial systems which may be less accessible to equity-focused program design goals. And the location-specificity of procurement RFPs, while valuable for targeting high-value deployment, limits the geographic scale of any individual procurement program.

Cost Structure

The mechanism cost of utility procurements is the contracted compensation paid to aggregators and VPP operators by the utilities to which they provide services under the terms of the executed service contracts. In a competitive procurement that functions as intended, this cost should approximate the minimum amount necessary to make the deployment of qualified distributed resources economically viable given the revenue available from other mechanisms (i.e., retail rate savings, grid services tariff compensation, and applicable incentive programs). Theoretically, if contract payments are less than the value of the benefits the utility receives (measured as avoided capital expenditure, reduced capacity procurement costs, or avoided energy costs) the benefit-to-cost ratio of the mechanism exceeds 1.0 and ratepayers are net beneficiaries.

The converse case, contracts proceeding despite a benefit-to-cost ratio below 1.0, such that ratepayers bear a net cost, does occur, but generally only where a procurement mandate or deployment target supersedes, or operates independently of, a pure cost-effectiveness screen. California's AB 2514 storage procurement framework illustrates this dynamic: the statute directs load-serving entities to procure storage capacity against fixed megawatt targets across three grid domains, with utilities required only to *consider* cost-effectiveness in structuring those procurements rather than to demonstrate a benefit/cost ratio above 1.0 for each contract.[69, 70] Some jurisdictions have built explicit exception processes to govern this tension directly. Maryland's energy storage procurement order, for example, requires the utility to seek Commission approval if procurement bids materially exceed the cost caps the Commission has established–formalizing a regulatory pathway for the utility to proceed with procurement even when compensation exceeds the pre-set cost benchmark, subject to case-by-case Commission review.[71] Other states have attempted to preserve a cost screen within a binding mandate rather than waive it outright: Massachusetts' 2024 storage law sets a hard 5,000 MW deployment target by 2030 but qualifies part of that target (750 MW of multiday storage, with the phrase "if commercially available at a reasonable cost") signaling legislative intent to avoid mandate-driven overspending even while making deployment itself non-discretionary.[72] Across these examples, the common thread is that below-1.0 procurements are not the product of routine competitive bidding gone wrong, but of statutory or regulatory deployment obligations, typically tied to reliability, decarbonization, or state policy targets, that define compliance independently of, or as an exception to, a ratepayer cost test.

Procurement contracts generally specify that the contracting aggregator is responsible for ensuring that the distributed resources under contract do not operate in ways that increase system costs. Any actual system cost increases attributable to the contracted resources should be minimal relative to the contract payments, which are designed to reflect the net value of the procured services. Administrative costs, including RFP design, bid evaluation, contract management, metering and verification, and regulatory approval processes, constitute a non-trivial component of the total mechanism cost and should be incorporated into program cost-effectiveness evaluations.

Deployment Incentives

Mechanism Description and Operation

Deployment incentives are financial instruments, including upfront rebates, grants based on the capacity of an energy system, and performance-based payments, designed to reduce the net

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[69] Energy Storage Systems, Cal. Stats. 2010, ch. 469 (A.B. 2514, Skinner), codified at Cal. Pub. Util. Code § 2836 et seq. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

[70] California Public Utilities Commission. (2013, October 17). *Decision Adopting Energy Storage Procurement Framework and Design Program*, Decision 13-10-040, Rulemaking 10-12-007. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

[71] Maryland Public Service Commission. (2026) *Order No. 92281, In the Matter of the Maryland Energy Storage Program*, Case No. 9715. https://psc.maryland.gov/wp-content/uploads/2026/04/ORDER_1.pdf

[72] Massachusetts General Court. (2024). *An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers,* 2024 Mass. Acts ch. 239, §§ 94–98 (inserting § 83E into An Act Relative to Green Communities). https://malegislature.gov/Laws/SessionLaws/Acts/2024/Chapter239

capital cost of distributed solar and storage installations. These are designed to expand the population of customers for whom the investment is economically viable. Unlike retail rate design, grid services tariffs, and procurement programs, which compensate distributed energy resources for the operational value they provide over time, deployment incentives are primarily oriented toward the installation decision since they lower the barrier to adoption without necessarily directing how the installed asset will operate.

This operational distinction has important implications for cost-effectiveness analysis. An incentive program that subsidizes the installation of a battery energy storage system without establishing any requirement or price signal governing how the battery is dispatched can create problems. It may accelerate deployment without ensuring that the deployed asset provides the grid services it is theoretically capable of providing. Conversely, some programs are already using a deployment incentive designed in coordination with retail rate structures and grid services programs to bridge the economic gap between current installation costs and the value the customer can capture through operational revenues, enabling the asset to be deployed and operated in a manner that produces benefits across multiple value streams.

Key structural features of deployment incentive programs include:

- **Upfront versus performance-period payments:** Some programs pay a lump-sum incentive at the time of installation, verified by system commissioning data. Others pay annual or monthly incentives over the first several years of system operation, sometimes called performance-based incentives (PBIs). PBI structures are typically tied to energy production (kilowatt-hours generated, as distinct from grid-service dispatch events) and provide a continuing revenue stream that can support project financing. Massachusetts' SMART program is a prominent example of a PBI structure.[73, 74]

- **Capacity-based compensation:** A second, independent dimension along which deployment incentives vary is how the incentive amount itself is calculated, separate from when it is paid. Capacity-based compensation pays on a per-watt (/W) basis for installed solar capacity or a per-watt-hour($/Wh) basis for installed solar capacity or a per-watt-hour($/Wh) basis for installed storage capacity, without reference to the asset's subsequent operational output or grid service delivery; this structure is administratively simple but decoupled from performance. Fixed-amount incentives–common in a number of state rebate programs–pay a flat dollar amount per participating system or customer, regardless of system size, cost, or capacity. Percentage-of-cost incentives–the structure underlying most state tax credits and some rebate programs–compensate a defined share of the customer's installed system cost, scaling the incentive with project cost rather than with capacity or output. These two dimensions are independent rather than mutually exclusive: a capacity-based or fixed-amount incentive can be paid either upfront or over a performance period, though in practice capacity-based and fixed-amount structures are most commonly paired with upfront payment, while percentage-of-cost incentives (such as

[73] Massachusetts Department of Energy Resources. (n.d) *225 CMR 20.00: Solar Massachusetts Renewable Target (SMART) Program*. https://www.mass.gov/solar-massachusetts-renewable-target-smart
[74] Massachusetts Department of Public Utilities. *Solar Massachusetts Renewable Target Program Tariff*, D.P.U. 17-140. https://www.mass.gov/info-details/smart-filings-and-tariffs

tax credits) are nearly always claimed as a one-time payment tied to installation rather than structured as an ongoing PBI.

• **Declining block structures:** Many programs use a declining schedule in which the per-watt or per-watt-hour incentive rate decreases as cumulative program enrollment fills defined capacity tranches. Declining blocks create market urgency for early adoption, which tend, therefore, to be limited to those who can move first and fastest due to access to capital and/or financing, provide a transparent price-discovery mechanism as the market develops, and allow the program budget to extend further as technology costs decline. They also require careful calibration to avoid boom-bust deployment cycles driven by block transitions.

• **Equity carve-outs and adders:** Contemporary deployment incentive programs increasingly reserve a portion of program funding--often at enhanced incentive levels--for qualifying low-income customers, environmental justice communities, affordable housing developments, or other targeted populations. California's Self-Generation Incentive Program (SGIP) is a notable example that is chronically oversubscribed (thus is not able to serve all of the expressed interest), offering per-kilowatt-hour rebates for battery storage that range from approximately $150/kWh for general market residential customers to $1,000/kWh for customers in high fire-threat districts or with qualifying low-income status.[75] Of note, as of late 2025, all new SGIP application submissions became limited to a new "Residential Solar and Storage Equity" (RSSE) budget, whose funding has already been fully reserved.[76]

• **Federal incentive stacking:** State deployment incentive programs are typically designed to be compatible with, and layered on top of, the federal Investment Tax Credit (ITC) for solar and storage (which ended December 31, 2025) and, where applicable, accelerated depreciation under the Modified Accelerated Cost Recovery System (MACRS).[77] The combined effect of federal and state incentives is material to project economics and must be accounted for in any assessment of the minimum incentive level required to make a deployment decision economically viable.

Program Administration and Funding

Deployment incentive programs are funded and administered through several distinct mechanisms, each with different implications for program stability, geographic reach, and accountability structures. The most common funding mechanism for large-scale state programs is

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[75] Verdant Associates, LLC. (2025, March 7). *2023 SGIP Impact Evaluation*. Prepared for Pacific Gas and Electric Company, SGIP Working Group. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2023_sgip_impact_evaluation.pdf

[76] Connected Energy. Residential Solar & Storage Equity Program. https://ca.storeenergy.com/residential-solar-storage-equity-program/

[77] Under the One Big Beautiful Bill Act (signed July 4, 2025), the residential solar ITC (Section 25D) terminated as of December 31, 2025, with no phase-down, while the commercial/third-party-owned ITC (Section 48E) remains available on an accelerated timeline. Storage ITC eligibility, including for standalone systems not paired with solar, was not subject to this accelerated phase-out and remains in place under the original timeline into the early 2030s. Additionally, 100% bonus depreciation supplements the standard MACRS schedule for qualifying property acquired after January 19, 2025.

a ratepayer surcharge: a per-kilowatt-hour charge assessed on all customers in the utility's service territory, the proceeds of which are directed to a program administrator (which may be the utility itself, the state energy office, or an independent third-party administrator) for disbursement as installation incentives. Ratepayer surcharges provide a stable, recurring revenue stream but constitute a cost imposed on non-participating customers, creating equity and cost-allocation questions that must be addressed in program design.

Programs may alternatively be funded through appropriated state general fund revenues, revenues from cap-and-trade or carbon pricing programs (such as California's Greenhouse Gas Reduction Fund, which has provided a significant source of SGIP funding), or federal grant programs, including Department of Energy awards and Treasury programs established under the Inflation Reduction Act.[78] Federal sources, however, have proven considerably less stable than state or ratepayer-funded revenue streams: beginning in early 2025, a substantial share of DOE clean energy grant funding was frozen or canceled,[79] and the One Big Beautiful Bill Act (enacted July 2025) rescinded unobligated Inflation Reduction Act balances for several federal grant and loan programs.[80]

Program administration is typically assigned to utilities, state energy offices, or independent program administrators who manage application processing, installation verification, incentive disbursement, and program reporting. The choice of administrator affects the pace of program implementation, the quality of program data, and the administrative overhead costs that reduce the net value of program spending for eligible customers.

A separate consideration is whether customers can access the upfront capital needed to use these incentives at all. Most deployment incentives offset only a portion of installed cost, and customers must still finance the remainder--or front the full cost until a rebate or credit is later realized. For customers without ready cash or credit access, this can make an incentive practically unusable regardless of its nominal value. Some states and utilities pair deployment incentives with financing mechanisms designed to close this gap, including low-interest loan programs and on-bill financing, where loan repayment is collected through the customer's regular utility bill. Where such financing is unavailable, an incentive program's practical reach may fall well short of its nominal design, particularly for lower-income or lower-credit customers–a consideration policymakers may want to weigh alongside incentive structure and program administration.

Strengths and Limitations

The principal strength of deployment incentives as a policy mechanism is their direct and demonstrable effect on near-term installation volume. By reducing the net capital cost of solar and storage installations to prospective hosts, incentive programs broaden the addressable market to customers who, given the revenue available from retail rate savings and grid services

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[78] California Public Utilities Commission. (n.d.) *Self-Generation Incentive Program*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program
[79] Exec. Order No. 14154, *Unleashing American Energy*, 90 Fed. Reg. 8353 (Jan. 20, 2025). https://www.federalregister.gov/documents/2025/01/29/2025-01956/unleashing-american-energy
[80] One Big Beautiful Bill Act, Pub. L. No. 119-21, § 41001, 139 Stat. (2025) https://www.congress.gov/bill/119th-congress/house-bill/1/text

compensation, would not otherwise find the investment economically justified. Incentive programs can also broaden deployment to households who do not otherwise have the capital or the credit. Deployment incentives are also relatively easy for customers and contractors to understand on their own, since the incentive amount is usually stated in terms such as so much per watt, a flat rebate, or a percentage of cost. This simplicity is greatest when the incentive covers the full cost of installation and there are no other tradeoffs to weigh. In that case, the decision to move forward is straightforward. More often, though, an incentive covers only part of the cost, and prospective hosts still have to weigh it against other incentives and financing options available to them (other rebates, tax credits, financing costs, and any savings from retail rates or grid services) to figure out the real financial benefit. In these more typical cases, understanding any one incentive is not the same as making an easy overall decision, since the customer's actual choice depends on how several incentives and costs add up together.

The primary limitation of deployment incentives is that they pay for installing a system, not for how it's used afterward. A capacity-based rebate that subsidizes the installation of a battery storage system does not, by itself, ensure that the system will be operated in a manner that provides grid services, peak demand relief, or other system benefits beyond the host customer's own bill savings. The grid value of an incentivized installation is therefore a function of the retail rate structure and any grid services programs to which the customer has access, and not of the incentive itself. For cost-effectiveness evaluation purposes, this means that deployment incentives should not be evaluated in isolation, but in combination with the other mechanisms that govern the operational behavior of the assets they enable.

Deployment incentive programs are also subject to budget constraints. Unlike retail rate design (which, once approved, applies automatically to all eligible customers) or grid services tariffs (which can in principle accommodate unlimited enrollment if the program is designed as an open tariff), deployment incentive programs are funded from finite appropriations or ratepayer surcharge pools. When programs are oversubscribed, waitlists develop, creating market uncertainty that can deter installer investment and reduce the stability of the distributed energy resource supply chain. Declining block structures partially address this issue by providing a predictable trajectory for incentive reductions, but require accurate enrollment forecasting to calibrate effectively. Finally, upfront incentives paid at installation create a one-time transfer that does not persist over the operational life of the asset; as technology costs continue to decline, the minimum incentive required to bridge the economic gap will also decline, requiring periodic program recalibration to avoid over-subsidizing installations that would have been deployed with a lower incentive payment.[81, 82]

Cost Structure

The mechanism cost of deployment incentive programs is primarily the incentive payments disbursed to eligible customers and installations. These payments are typically expressed on a per-watt ($/W) or per-watt-hour ($/Wh) basis to facilitate comparison with the benefit values estimated

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[81] Cory, K. et al. (2008, March). *Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments*. National Renewable Energy Laboratory. https://docs.nlr.gov/docs/fy08osti/43115.pdf
[82] *see also* Cory, K., & Coggeshall, C. (2007). *Photovoltaic Incentive Design Handbook*. NREL/TP-640-40845. National Renewable Energy Laboratory. https://www.osti.gov/biblio/897437

for the installed resources. To construct a meaningful benefit-cost evaluation of an incentive program, benefit estimates should be expressed in compatible per-unit terms–capturing the system value per kilowatt of solar deployed or per kilowatt-hour of storage deployed under the program. This normalization enables comparison of the incremental cost of the incentive against the incremental system value it enables, accounting for the contribution of other mechanisms (retail rates, grid services programs) to that value realization.

Administrative costs–including program design, marketing, application processing, installation verification, incentive disbursement, and reporting–constitute an additional component of total mechanism cost. These costs vary substantially by program scale and complexity but only represent a material fraction of total program expenditure in smaller or more targeted programs.

At scale, solar-only installations deployed through incentive programs have the greatest potential to generate increased system costs, because their non-dispatchable generation profile may not align with system capacity needs at times of peak demand. As solar penetration increases, this misalignment can intensify, increasing the marginal system costs attributable to additional solar-only deployments. Storage-enabled installations mitigate these dynamics, but only to the extent that the retail rate and grid services structures applicable to enrolled customers create incentives for storage dispatch that aligns with system needs. This interaction between incentive program design and the operational incentive structures created by other mechanisms is central to the portfolio-level cost-effectiveness analysis addressed in subsequent sections of this report.

Policy Mechanism Interactions and Portfolio Considerations

The four mechanisms described above are not mutually exclusive options; rather, they are complementary instruments that operate simultaneously and interact in ways that are critical to understanding the cost-effectiveness of distributed solar and storage policy at the portfolio level.[83] In other words, a BTM solar-plus-storage system in Washington could be governed by all four mechanisms at once: an incentive program could make the investment economically viable; a retail rate structure could govern the system's baseline dispatch behavior and export compensation; a grid services program could overlay additional dispatch signals and compensation during peak events; and the aggregation of many such installations could be subject to a utility procurement contract. The value realized by Washington ratepayers from distributed solar and storage is therefore a function not of any individual mechanism in isolation but of the portfolio of mechanisms in effect and the degree to which they are designed to work coherently together.

This portfolio perspective has three important implications for policy design:

- **The cost-effectiveness of a deployment incentive program cannot be evaluated without reference to the retail rate structure and grid services programs that determine how the incentivized assets will operate.** An incentive that enables the

[83] California Public Utilities Commission. (2018, January 11). *Decision Adopting Multiple-Use Application Rules for Storage*, Decision 18-01-003, Rulemaking 15-03-011. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.PDF

deployment of a storage system that will be dispatched by a well-designed grid services program to provide peak capacity relief is substantially more cost-effective (on a system value per dollar of incentive expenditure basis) than an incentive that enables the deployment of the same system in a regulatory environment where no grid services compensation exists and where retail rates do not create strong dispatch incentives.

- **Retail rate design and grid services tariffs can themselves influence deployment decisions by making the investment more or less attractive**, functioning as partial substitutes for upfront incentives as the revenue environment improves.
- **Procurement programs depend on the prior existence of viable paths for customer acquisition and distributed resources deployment to make aggregation viable.** Retail rate design, interconnection rules, etc. that create favorable installation economics therefore create the preconditions for effective procurement programs.

These interdependencies suggest that the sequencing and coordination of policy mechanism design is as important as the design of any individual mechanism. The research conducted in Phase 2, including the characterization of benefit realization and cost structure by mechanism presented in subsequent sections, is intended to provide the analytical foundation for Washington policymakers to evaluate and design this portfolio of mechanisms in an integrated and evidence-based manner.

Table 3. Distributed solar and storage: Summary of four policy mechanisms

These four policy mechanisms are not mutually exclusive. A single rooftop solar-plus-storage system may be subject to all four at once. These mechanisms are best evaluated as a portfolio rather than in isolation, because the value they realize depends on how they interact.

	Retail rate design	Grid services tariffs	Utility procurements	Deployment incentives
What it does	Sets export compensation (NEM, value-of-solar, net billing), TOU rates, demand charges, fixed charges — shapes day-to-day bill economics	Pays separately for measured grid services (peak relief, voltage support) via standing, open-enrollment programs	Competitive RFPs where utilities contract aggregators/VPPs for dispatchable capacity	Upfront rebates, grants, or subsidies that lower installation cost
Primarily affects	Both the install decision and ongoing dispatch behavior	Both the install decision and ongoing dispatch behavior	Aggregated portfolios of installations	The install decision only — "operationally agnostic"

	Retail rate design	Grid services tariffs	Utility procurements	Deployment incentives
Who sets it / how	WA UTC for investor-owned utilities via rate cases (12–24 months); governing boards for public/municipal utilities	Regulatory filings, often alongside rate cases; eligibility and rates specified in tariff	Utility/regulator identifies a grid need → RFP → aggregator bids → PPA/contract; commission approval required	Funded via ratepayer surcharge, state general funds, carbon-pricing revenue, or federal grants; administered by utility/state office/third party
Key strength	Scalable (automatic for all eligible customers), durable, comprehensive reach	Precise — pays for actual measured service at the right time/location	Greatest locational/temporal precision; competitive bidding can yield net-positive ratepayer value	Directly expands the addressable market; simple for customers to understand
Key limitation	Coarse: can't price locational value or most grid services; slow to update; risk of cost shift to non-participants	Budget caps create waitlists; admin-set rates may lag true value; dispatch must be calibrated to avoid battery degradation	High transaction/admin overhead per cycle; favors larger C&I systems; geographically limited	Doesn't ensure the asset is operated for grid value; budget-constrained; needs periodic recalibration as costs fall
Mechanism cost	Cost shift = (export rate − avoided cost) × export volume; zero if compensation = avoided cost	Compensation priced at calculated service value (benefit-cost ratio ≈ 1.0 by design) + admin/metering costs	Contracted payment to aggregators; ratio can exceed 1.0 if competition drives price below value delivered	Incentive payment ($/W or $/Wh) + admin costs; doesn't by itself guarantee grid value

	Retail rate design	Grid services tariffs	Utility procurements	Deployment incentives
Example	PG&E's storage-optimized rate schedule; California NEM 3.0 net billing	Massachusetts ConnectedSolutions; New York's VDER tariff [84]	Con Edison's Brooklyn-Queens Demand Management Program (non-wires alternative)	California's SGIP (storage rebates, scaled by equity tier)

Minimizing Cost Shift: A Policy Objective Grounded in Washington's Statutory Framework

In utility regulation and energy policy, a cost shift occurs when one group of customers does not pay the full costs attributed to the electric system, and those costs are instead recovered from other customers through rates. With respect to rooftop solar, the term typically describes the claim that customers with solar reduce their electricity purchases and bills while continuing to rely on shared grid infrastructure. If the utility's fixed costs are not fully recovered from those customers, the unrecovered portion may be spread across non-solar customers.

Washington's clean energy statutes establish a policy objective this report adopts as its organizing frame: distributed solar and storage deployment is expected to be broadly accessible and to avoid shifting costs from participating ratepayers onto low- and moderate-income and disadvantaged-community ratepayers who cannot access the technology. CETA (RCW 19.405) requires utilities to pursue the equitable distribution of energy benefits and the reduction of energy burdens for vulnerable populations. The Climate Commitment Act directs at least 35% of cap-and-invest revenues to investments providing direct benefits to vulnerable populations. The HEAL Act establishes a statutory expectation that clean energy policy be designed with explicit attention to its distributional consequences.[85] These goals are why this report evaluates each policy mechanism—retail rate design, grid services tariffs, utility procurements, and deployment incentives—specifically in terms of the cost shift each one produces, rather than in terms of total deployment or total system cost alone.

Before applying this framework, three terms need to be distinguished clearly, since they are easy to conflate:

- **System costs**, as used throughout this report, refers to utility system costs--the utility's own generation, transmission, distribution, and capacity costs--not the cost to the host of installing, operating, or maintaining a distributed asset. Host-side installation and

[84] New York State Energy Research and Development Authority. (n.d.) *Value Stack Resources*. https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Resources

[85] Climate Commitment Act, RCW 70A.65.230 https://app.leg.wa.gov/rcw/default.aspx?cite=70A.65.230 (requiring a minimum of 35%, with a goal of 40%, of cap-and-invest proceeds to provide direct and meaningful benefits to vulnerable populations within overburdened communities).

maintenance costs are real, but they are borne privately by the host (or the host's financing arrangement) and are not a ratepayer cost; they do not enter the cost-shift calculation described below.

- **Avoided costs** are the subset of utility system costs that a utility does not have to incur because a distributed asset serves a need in its place (see Section VII). Avoided cost is the benchmark against which mechanism compensation is measured.
- **Cost shift** is what results when a mechanism compensates a distributed asset owner at a rate that exceeds the utility's avoided cost. The difference is not eliminated; it is paid by other ratepayers who do not own the asset producing the benefit. Cost shift is therefore a transfer between ratepayer groups, not a net increase in total system costs--a distinction that matters throughout the discussion below. More detailed discussion is found in Appendix E.

This report distinguishes cost shift from the two cost factors prioritized here, increased bulk capacity costs and increased distribution capacity costs. Both represent real, measurable increases in the utility's system resource costs attributable to distributed energy resource deployment, the kind that would appear in a resource planning or interconnection study regardless of how those resources are compensated. Cost shift is not in this category: it is a **mechanism cost**, meaning it reflects how ratepayers collectively compensate installers, owners, and operators of solar and storage under a given policy mechanism, not a change in the utility's underlying resource costs. For grid services tariffs, utility procurements, and deployment incentives, the mechanism cost is simply the service, contract, or incentive payment made under the program. For retail rate design, the mechanism cost is cost shift itself: the difference between the export compensation rate embedded in the rate structure and the utility's actual avoided cost, multiplied by the volume of exports.

Cost shift as equity concern and equity opportunity

Even where cost shift is modest in the aggregate, it carries a specific distributional risk: the potential for costs to move from relatively affluent ratepayers--those most likely to have installed rooftop solar--to ratepayers who cannot access the technology. This concern is not resolved by choosing one mechanism over another; it is addressed through how each mechanism is designed. Read against Washington's statutory background, cost shift is not a reason to limit the growth of distributed solar and storage--it is a design constraint: mechanisms are expected to extend access broadly, price grid services accurately, recover shared costs equitably, and protect—and ideally benefit--the ratepayers least able to absorb rate increases. Washington's Community Solar Law and PacifiCorp's proposed Equitable Access Credit, which would extend NEM-equivalent economics to low-income customers under a net billing successor, illustrate what mechanism design oriented around this objective can look like.[86, 87]

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[86] Community Solar Programs, RCW 82.16.170; *Community Solar Expansion Program*, RCW 82.16.183. https://app.leg.wa.gov/rcw/default.aspx?cite=82.16.170

[87] Washington Utilities and Transportation Commission, Docket No. UE-250695, *In the Matter of PacifiCorp's Proposed Net Billing Successor Tariff (Schedules 135 & 138)*. https://www.utc.wa.gov/casedocket/2025/ue-250695

Cost-shift minimization versus utility cost minimization

A natural question is how minimizing cost shift, subject to a deployment goal for distributed solar and storage (DSS), differs from simply minimizing utility system costs subject to the same deployment goal. The two are related but not equivalent, and the difference matters for how this report's recommendations are best read.

Utility cost minimization is an efficiency objective: for a given level of DSS deployment, it asks how to minimize the utility's net system costs--the two cost factors described above, offset by whatever avoided costs that deployment produces. This is a question about the *total resource cost* of achieving a deployment target, independent of who ultimately bears it.

Cost-shift minimization is a distributional objective: it asks how to minimize the gap between what ratepayers collectively pay asset owners under a given mechanism and what the utility actually avoids in system costs as a result. Because cost shift is a transfer between ratepayer groups rather than a net addition to total system costs, minimizing it does not, by itself, minimize the utility's total system costs, and minimizing the utility's total system costs does not, by itself, minimize cost shift.

The two can diverge in both directions. A mechanism can achieve zero cost shift--compensation set exactly at avoided cost--while still being a comparatively expensive way to reach a given deployment target, if administrative costs, financing costs, or slower resulting deployment rates raise the utility's total system costs relative to an alternative mechanism that pays more than avoided cost but achieves the deployment target faster or at lower administrative overhead. Conversely, a mechanism that minimizes the utility's total system costs might still permit meaningful cost shift, if compensating certain resource owners above avoided cost turns out to be the least-cost way, in aggregate program terms, to secure the deployment needed to avoid a larger capital expenditure.

In practice, the two objectives often point toward similar mechanism designs, because compensation calibrated to actual avoided cost tends to be both distributionally fair and reasonably efficient. But they are not logically equivalent, and a policymaker optimizing only for utility cost minimization could accept substantial cost shift as long as total system costs were minimized. Washington's statutory framework does not leave that choice open: CETA, the Climate Commitment Act, and the HEAL Act direct the state toward the distributional objective specifically, which is why this report frames mechanism design around minimizing cost shift, not solely around minimizing total utility system cost.

Mechanism design principles for minimizing cost shift while enabling deployment

Whether a cost shift arises, and how large it is, depends less on distributed solar or solar-plus-storage itself than on how the policy mechanisms described above are designed. For each of the four mechanisms described above, the following design principles identify the choices that most directly align compensation with the value distributed resources provide, ensure that participating customers continue to contribute to shared system costs, and broaden access to distributed solar's benefits:

Export compensation calibration is the most direct lever for minimizing cost shift in retail rate design. A rate design in which export compensation precisely equals avoided cost produces zero cost shift by construction. Moving toward time-differentiated export credits that reflect the marginal value of solar generation when it is actually produced—rather than the bundled retail rate—reduces the mismatch between compensation and cost causation without requiring an abrupt reduction that disrupts the solar market, as California's NEM 3.0 experience cautions.

Non-bypassable charges, when included in the retail rate rather than the export credit, ensure that all customers—including those who reduce net volumetric purchases through solar—contribute to shared public purpose programs, low-income assistance, and infrastructure recovery, limiting the revenue shortfall that drives cost shift.

Fixed and demand charge design can recover more of the grid's fixed infrastructure costs in ways that do not vary with net energy consumption, reducing the degree to which solar customers can offset their contribution to shared system costs through volumetric bill reductions. Income-differentiated fixed charges or targeted bill credits can address the regressive risk this approach would otherwise create.

Grid services tariffs and utility procurements, when well-designed, carry inherently low cost shift because they compensate distributed solar-plus-storage systems specifically for the grid services they demonstrably provide, at rates calibrated to the value of those services. As the residential solar-plus-storage attachment rate continues to climb--25% nationally in 2024, and 57% of new California installations that year--grid services programs become an increasingly important complement to retail rate design.[88, 89]

Community solar expansion and income-targeted deployment incentives[90] address the distributional concern at its source, by enabling low- and moderate-income customers, renters, and multifamily residents to participate in the benefits of distributed solar rather than bearing a disproportionate share of its costs. When access to distributed solar is broad, the political and analytical premise of cost shift as a regressive transfer from non-participants to affluent solar owners becomes substantially weaker.

Cost shift, in short, is not a fixed feature of distributed solar and storage as a technology—it is a variable feature of how policy mechanisms are designed. Washington's statutory commitment to clean, reliable, affordable, and equitable energy provides both the mandate and the framework for designing those mechanisms well.

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[88] Wood Mackenzie. (2024, June). *The State of US Distributed Solar-Plus-Storage*. https://www.woodmac.com/news/opinion/the-state-of-us-distributed-solar-plus-storage/

[89] Wood Mackenzie & Solar Energy Industries Association. (2024) *U.S. Solar Market Insight*, 2024 editions. https://seia.org/research-resources/us-solar-market-insight/

[90] The Washington State Department of Commerce's Solar for All program, currently paused, is a fund designed to bring the benefits of solar energy to all income-qualified households, disadvantaged communities and tribes. The program is administered by the WSU Energy Program. https://www.commerce.wa.gov/epic/solar-for-all/

VI. FACTOR SELECTION

Our earlier work identified more than 60 potential benefit and cost factors associated with the deployment of distributed solar and storage resources in Washington State, spanning five major system categories: generation, transmission, distribution, host customer, and societal. Attempting to quantify all 60-plus factors would have exceeded the research resources available and would have produced a study of unmanageable scope without proportionate analytical value. At the same time, selecting too narrow a set of factors risked producing findings that were not representative of the full range of methodological challenges the project needed to address, or that reflected implicit value judgments about which impacts matter most rather than a principled analytical framework.

The team therefore designed a structured, multi-stage selection process with a specific and deliberate objective: not to identify or decide the most important factors, nor the factors of greatest interest to any particular stakeholder, but a representative set–one that together exercises the full range of quantification approaches, spans the diversity of system categories and impact types, and reflects Washington's specific energy system characteristics. The resulting selection of eight benefit factors and two cost factors was validated by the project's Oversight Committee before research proceeded.

Construction of the Full Factor List

Building on the benefit and cost taxonomy developed in the initial stages of this research, **potential** impacts were organized into five system-tier categories: 1) generation (impacts on bulk power supply costs and resources), 2) transmission (impacts on the high-voltage transmission system), 3) distribution (impacts on the local distribution system serving end-use customers), 4) host customer (impacts on the customers who host the distributed resources), and 5) societal (broader environmental, economic, and equity impacts not captured in utility cost accounting). Within each category, the taxonomy identified specific, discrete impact types–such as avoided bulk capacity costs, avoided distribution line losses, improved host customer resilience, and workforce development–that could in principle be quantified and incorporated into a benefit-cost analysis.

Before applying any selection criteria to this list, the research team subjected it to two external cross-reference checks designed to test its completeness and alignment with established analytical practice.

Cross-Reference Against the National Standard Practice Manual

The National Standard Practice Manual (NSPM),[91] published by the National Efficiency Screening Project and widely adopted by state utility commissions as the authoritative framework for benefit-cost analysis of distributed energy resources, provides a comprehensive taxonomy of the categories of value that should be considered in distributed energy resource cost-effectiveness evaluations. The NSPM taxonomy spans avoided supply costs, avoided capacity costs, avoided

[91] National Association of State Energy Officials, *National Standard Practice Manual*, https://naseo.org/nesp/nspm

transmission and distribution costs, avoided environmental compliance costs, non-energy benefits, and participant benefits, organized within a multi-perspective analytical framework that considers the utility, ratepayer, participant, and societal viewpoints.

The cross-reference between the factor list developed for this work and the NSPM taxonomy confirmed strong alignment across the majority of categories: virtually every factor in the Interim Report list mapped to a recognized NSPM impact category, providing confidence that its taxonomy was grounded in established analytical practice. The cross-reference also identified a small number of gaps–categories present in the NSPM that the framework in the Interim report had not yet explored. These included non-energy impacts (such as the value of improved indoor comfort and productivity attributable to more reliable energy access), fuel price risk mitigation (the value of reducing a utility's exposure to natural gas price volatility through increased reliance on non-fuel distributed resources), and program administrative costs (the full cost of designing, operating, and evaluating the policy mechanisms through which distributed resources are deployed). These gaps informed subsequent decisions about the scope of the cost factor analysis in this report. Appendix C shows these comparisons.

Cross-Reference Against the Prior E3 Washington Analysis

The second external check compared the Interim Report's factor list against a prior value-of-solar analysis conducted for Washington State by the consulting firm Energy and Environmental Economics (E3).[92] The E3 study provided a useful benchmark because it was Washington-specific, had been conducted in the existing regulatory context directly relevant to this project, and reflected the analytical choices of experienced practitioners working within the constraints of a defined scope and timeline.

This comparison showed that the Interim Report's list and the E3 framework differed in scope and emphasis across several dimensions. The E3 analysis focused primarily on generation-tier and transmission-tier value streams–avoided energy costs, avoided capacity costs, and transmission-related benefits–with distribution-tier impacts, host customer impacts, and societal factors covered in less depth. The Interim Report's taxonomy, by contrast, explicitly identified distribution system benefits and costs, a broader array of host customer impacts, and a range of societal factors—including equity-related impacts, workforce development, and hydropower interactions—that were outside the scope of the E3 study. Appendix F shows these comparisons.

The research team treated this comparison not as a basis for adjusting the Interim Report's list to match the E3 scope, but as confirmation that prior analytical work had made deliberate choices driven by time, resource, and scope constraints. The mandate of this project–to develop a rigorous and complete methodology for valuing distributed solar and storage in Washington–allowed engaging with the full range of impact categories, even where established quantification methods are less mature.

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[92] Energy and Environmental Economics, Inc. (E3). (2023, December 21). *Benefits and Costs of Net Energy Metering in Washington: Final Report*. Prepared for a group of Washington electric utilities and the Washington Public Utility Districts Association (WPUDA). https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefits-and-Costs-of-Net-Energy-Metering-in-Washington_2023-12-21.pdf

Characterization of the Full Factor List

Following the external cross-reference checks, and prior to initiating the selection process, the research team organized and characterized the full factor list along two analytical dimensions. This characterization served two purposes: it provided the structured basis for selection decisions, and it produced a working map of the methodological landscape that the research for this report would need to navigate.

Categorical Organization

Each factor was assigned to one of the five major system-tier categories: generation, transmission, distribution, host customer, and societal. This categorization kept the selection from clustering around familiar or easily measured factors. The final set includes factors from four of the five categories. Only transmission is not represented by its own factor; its effects are captured within the avoided energy and bulk capacity factors.

Two-Axis Characterization

Each factor was then assessed along two analytical axes that together capture the practical considerations most relevant to factor selection for a research project of defined scope and resources (Table 4).

The first axis represented the potential magnitude of impact in the Washington context. This included an assessment of how large the impact associated with a given factor could realistically be, given Washington's load profile, energy resource mix, regulatory environment, and the scale of distributed solar and storage deployment anticipated over the relevant planning horizon. Factors with high potential magnitude, such as avoided bulk capacity costs, exemplify where Washington utilities face significant future resource adequacy requirements based on current projections. These were given greater weight in the selection process than factors whose impacts, while theoretically real, are likely to be small relative to other value streams in Washington's specific context.

The second axis was analytical tractability. This assessed how well established existing quantification methodologies are for a given factor and how data-intensive their implementation would be in the Washington context. Tractability encompasses both the existence of documented methodological precedent – has this factor been quantified in regulatory proceedings or academic studies in other jurisdictions, and are the methods transferable to Washington? – and the practical data requirements for implementation, including the availability of Washington-specific utility data, load profiles, and system modeling outputs needed to apply those methods.

The two-axis characterization produced a working typology of factors across four cells. High-magnitude and high-tractability factors represent the most compelling candidates for inclusion, where both the analytical case and the practical implementation path are clear. High-magnitude and lower-tractability factors, or those analytically important but methodologically challenging, were candidates for inclusion precisely because developing methods for them is a core project objective. Lower-magnitude / high-tractability factors (i.e., analytically accessible but of limited policy significance in the Washington context) and lower-magnitude / lower-tractability factors

(i.e., the weakest candidates for inclusion in a representative set) were not considered compelling candidates, though not necessarily excluded from the full factor list for future analysis. The characterization was explicitly acknowledged as approximate, since magnitude assessments in particular involve significant uncertainty, but provided sufficient structure to anchor the selection process in analytical rather than political criteria.

Selection Criteria and Process

With the full factor list organized and characterized, the research team applied a set of selection criteria around a representative rather than exhaustive or advocacy-driven factor set.

Primary criterion: methodological breadth. The selected factors, taken together, should require the research team to develop and demonstrate the range of quantification approaches that policymakers will need to apply across the complete factor list in future analyses. This criterion favored selections that collectively include well-established quantitative factors that document methodological precedent and help with Washington-specific calibration. It also favored analytically novel factors, where methods may be less mature, the data requirements are more demanding, or the causal pathways between distributed resource deployment and system impact are more complex. The latter was important to include, since a representative set dominated by only well-established factors would underserve the project's goal to develop a more rigorous and complete methodology; one dominated by analytically novel factors would risk producing findings too speculative to be actionable.

Secondary criterion: categorical coverage. The selection must include at least one factor from each of the five major system-tier categories. This constraint ensured that the methodological demonstration would be relevant to the full range of system impacts, not merely to those in the generation or transmission tiers where quantification methods are most mature.

Tertiary criterion: Washington relevance. Among factors of comparable magnitude and tractability, preference was given to those whose quantification is most directly conditioned by features of Washington's energy system that distinguish it from the generality of national experience. The two most prominent of these attributes are 1) the dominant role of hydroelectric generation–which creates interactions between distributed solar and storage deployment and hydro dispatch operations that are largely absent from most out-of-state analytical precedent–and 2) the state's unusually high proportion of electric end-use services, which amplifies the equity implications of electricity rate changes and makes the distributional analysis of cost factors particularly important.

The team excluded factors whose core difficulty is proving the causal link between resource deployment and outcome as distinct from factors where that link is already established and the task is just measuring the impact's magnitude. Bulk and distribution system reliability and resilience (as distinct from host customer resilience, which was included) are examples. Yet, while the theoretical connection between distributed resource deployment and system-level reliability improvement is acknowledged in the literature, the causal chains are long, the empirical evidence is limited, and the quantification methodologies remain contested. Including such factors in the representative set for this phase of the project would have required the research team to resolve

foundational causal questions that exceeded the scope of the project. These factors remain on the full list for potential future analysis.

Oversight Committee Validation

Prior to finalizing the factor selection, the research team presented the characterized full list and the proposed representative set to the project's Oversight Committee (OC), with a framing that explicitly distinguished validation from prioritization. The team did not ask the OC to identify which factors mattered most from a policy perspective to avoid introducing advocacy into what was designed as an analytical process. Instead, the team asked whether the proposed selection was methodologically representative: did it span the relevant categories, exercise the necessary range of quantification approaches, and reflect Washington's specific system characteristics in a way that would make the Phase 2 findings useful to policymakers across the full range of future analytical applications?

OC feedback confirmed broad alignment with the proposed selection of factors and the analytical rationale supporting it. Committee members affirmed avoided energy costs as a standard inclusion in virtually all distributed energy resource cost-effectiveness analyses that provide the methodological foundation on which more novel factors build. The inclusion of market price impacts and hydropower-related factors was recognized as reflecting Washington-specific conditions that most out-of-state studies do not address. The exclusion of bulk system reliability and resilience factors from the representative set was confirmed as appropriate for this project, with acknowledgment that these factors warrant inclusion in future, more comprehensive analyses. The OC's input provided external confirmation that the analytical rationale was sound and the resulting set aligned with the scope of the project.

Selected Factors

The result of this process is a representative set of ten factors: eight benefit factors and two cost factors. Table 4 presents the selected factors organized by system-tier category, with a brief description of the impact each factor captures and its characterization on the two analytical axes. For reference, the full list of benefit and cost factors that were considered but not included, and recognizing that many are fairly common in other studies, is found in Appendix B.

Table 4. Selected Benefit and Cost Factors for Analysis

Category	Factor	Impact Captured	Magnitude	Tractability
BENEFIT FACTORS				
Generation	Avoided energy costs	Reduction in wholesale energy procurement costs attributable to displaced generation from distributed solar and storage dispatch	High	High

Category	Factor	Impact Captured	Magnitude	Tractability
	Avoided bulk capacity costs	Reduction in resource adequacy costs attributable to the effective load-carrying capability of distributed solar and storage resources during system peak periods	High	Moderate
	Market price impacts	The effect of distributed solar on wholesale electricity prices. When distributed solar reduces the amount of energy or capacity the grid needs to buy, it can also push down the price paid for whatever energy or capacity is still being bought–a separate effect from the avoided-cost savings described elsewhere. In simple terms: avoided cost is about buying *less*; DRIPE (Demand Reduction Induced Price Effect) is about paying a *lower price* for what's still being bought.[93, 94, 95, 96]	Moderate	Moderate

[93] **Methodological caveat:** DRIPE is a recognized but contested component of avoided-cost methodology. Industry experts disagree about when DRIPE should be included in cost-effectiveness tests, in part because the benefit is difficult to quantify, and the inability to fully validate DRIPE estimation methodology makes projected benefits inherently debatable, which complicates the case for including them in planning for cost-effectiveness purposes. Even within the same regional avoided-cost framework, states differ on whether to include DRIPE at all: the 2024 Avoided Energy Supply Components in New England (AESC) study notes that some New England states include DRIPE in their avoided-cost calculations and others do not. This report does not include a dedicated methodology reconciling the supply-curve or counterfactual assumptions underlying its avoided-cost and DRIPE estimates, and has not independently verified that the two are additive rather than overlapping. Readers should treat the DRIPE figure presented here as illustrative of a directionally plausible benefit rather than as a rigorously additive line-item alongside avoided generation and capacity costs; established avoided-cost frameworks, such as the AESC studies used across New England, define energy DRIPE and capacity DRIPE as line items distinct from avoided energy and capacity benefits, but doing so requires the kind of explicit, jurisdiction-specific methodology this report does not attempt. In addition, the direction of the price effect is not guaranteed to be negative (price-suppressing): capacity DRIPE in these frameworks is defined as the change in the price paid to resources holding a capacity supply obligation, resulting from the additional capacity bid into the market by the resource in question — meaning where distributed solar or storage capacity is bid in at a cost above the resource it displaces, the resulting price effect may be smaller than assumed, or in some auction structures, move in the opposite direction from what is typically expected.

[94] Regulatory Assistance Project, "The Value of Demand Reduction Induced Price Effects (DRIPE)," webinar summary, March 18, 2015, https://www.raponline.org/knowledge-center/the-value-of-demand-reduction-induced-price-effects-dripe/

[95] U.S. Department of Energy, State and Local Energy Efficiency Action Network (SEE Action), *State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All*, https://www.energy.gov/sites/default/files/2021-07/SEEAction-DRIPE.pdf

[96] Synapse Energy Economics, Inc., *Avoided Energy Supply Components in New England: 2024 Report*, prepared for the AESC 2024 Study Group, 2024, https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024.pdf

Category	Factor	Impact Captured	Magnitude	Tractability
	Hydropower ramping reduction	The net effect of distributed solar and storage on hydroelectric ramping requirements, which can be positive or negative depending on resource mix and dispatch pattern.[97]	Moderate	Low–Moderate
Transmission	Addressed within avoided energy and capacity costs (no standalone transmission factor selected for Phase 2 representative set)			
Distribution	Avoided distribution capacity costs	Reduction in distribution infrastructure investment costs attributable to peak demand reduction by distributed solar and storage at the local feeder or substation level	Moderate–High	Moderate
Host Customer	Increased host customer resilience	Value of avoided outage costs—including avoided income loss, food spoilage, medical equipment interruption, and related impacts—attributable to on-site backup power capability of storage-enabled distributed systems	Moderate	Moderate

[97] Distributed solar generation, taken on its own, tends to *increase* net load volatility rather than reduce it. As solar output rises through the morning and falls in the late afternoon–often in a matter of hours, and independent of underlying demand patterns–conventional generation must ramp to compensate, a dynamic widely documented in other high-solar-penetration systems (the "duck curve" phenomenon first characterized in California). In Washington, where hydroelectric generation provides the dominant source of fast-ramping capacity, this means distributed solar deployment, absent complementary dispatch, can increase the frequency and magnitude of rapid hydro ramping events rather than reduce them—the opposite of the effect this factor originally described. Distributed storage, by contrast, can reduce hydro ramping requirements where it is dispatched specifically to smooth net load–for example, charging during the solar output peak and discharging during the evening ramp–but this outcome depends on the storage system's dispatch strategy and is not an automatic consequence of storage deployment. A storage system dispatched for other purposes (e.g., customer bill savings via peak-shaving on the customer's own load, rather than grid-facing ramp smoothing) may provide little or no hydro-ramping benefit, and in principle could exacerbate ramping if its dispatch pattern is uncorrelated with, or works against, system net-load smoothing needs.
Given this, hydropower ramping is not treated as a reliably positive benefit factor of distributed solar and storage deployment generally. It is, instead, a factor whose sign and magnitude depend on (a) the solar-to-storage ratio in the deployed resource mix, and (b) whether storage dispatch is explicitly optimized for net-load smoothing rather than customer-facing objectives. Grid services tariffs or utility procurement contracts that specifically compensate storage for ramp-reduction or net-load-shaping services are the primary mechanism by which this factor could be reliably realized as a benefit; absent such a mechanism, the net effect of distributed solar and storage deployment on hydro ramping in Washington cannot be assumed to be beneficial and may be negative.

Category	Factor	Impact Captured	Magnitude	Tractability
	Improved economic wellbeing (distributional impacts)	Reduction in household energy burden—the ratio of energy expenditure to household income—attributable to distributed solar and storage adoption, with particular attention to impacts on low-to-moderate income households	Moderate–High	Moderate
Societal	Job creation and economic development	Direct and indirect employment and economic output effects attributable to distributed solar and storage installation, manufacturing, and operations activity in Washington State	Moderate	Low–Moderate
COST FACTORS				
System	Increased bulk capacity costs	Increased costs imposed on the bulk generation system by distributed solar and storage deployment and operation, including interconnection costs, potential infrastructure upgrades, and changes in system dispatch efficiency	Moderate	Moderate
	Increased distribution system costs	Incremental costs imposed on distribution systems by distributed solar and storage deployment and operation, including interconnection costs, potential infrastructure upgrades, and changes in system dispatch efficiency	Moderate	Moderate

Factors Not Selected and Rationale for Exclusion and Implications for the Findings

The factors not included in this report's representative set fall into several distinct categories, each reflecting a different analytical rationale for exclusion. Understanding these rationales is important both for interpreting the scope of this report and for informing the design of future analyses that build on this work. Descriptions of these can be found in Appendix I (Excluded Factors).

A fully comprehensive benefit-cost analysis of a specific policy mechanism or program design would need to incorporate the full range of factors identified in Appendixes B and I, using the methodological approaches demonstrated in this report as a starting point for factors where those approaches are applicable and developing additional methods for factors not addressed here.

These findings should therefore be understood as a methodological demonstration and an analytical foundation–a set of tools and documented approaches that Washington policymakers and regulatory staff can apply, extend, and refine as they design and evaluate specific policy mechanisms. The practical value of this foundation lies not in the production of definitive quantitative estimates for any particular program, but in establishing the analytical framework and methodological precedent within which such estimates can be credibly produced in future regulatory proceedings.

VII. POLICY MECHANISMS MATCHED WITH SELECTED BENEFIT FACTORS AND COST FACTORS

This section works through each benefit and cost factor identified earlier in the report (see Table 4) one at a time. For each factor, it presents the underlying calculation methodology, including formulas, distinguishing customer-side from utility-side perspectives where relevant. It then shows how that factor is quantified and compensated under each of the four policy mechanisms (retail rate design, grid services tariffs, utility procurement, and deployment incentives) with examples drawn from other states' programs.

Readers looking for the report's synthesized findings and policy recommendations, rather than the underlying technical detail, may prefer to skip ahead to Sections VIII and IX, which contain the summary tables and findings, and treat this section as a reference for how those conclusions were derived.

Box 5. Terms used throughout this section

Avoided cost: The cost that a utility would have incurred to provide a given amount of electricity or grid service, but no longer has to incur because another resource, such as distributed solar, storage or demand response, provides it instead.

Avoided energy cost: the cost of energy a utility does not have to generate or buy because a distributed energy resource supplies it instead.

Avoided capacity cost: the cost of generating capacity a utility no longer needs to build, buy, or reserve to meet peak demand because distributed energy resources reliably reduce load or supply power during peak periods

Avoided distribution cost: the cost of distribution infrastructure that a utility can defer or avoid building, such as substations, feeders, and transformers, because distributed energy resources reduce peak load on the grid.

Benefit categories

This section covers each of the eight benefit factors being examined in this work. For each factor, we summarize 1) how the factor is quantified in the literature and 2) how each factor may be realized using the different policy mechanisms, when appropriate.

Avoided energy costs

Avoided energy costs are well documented and calculated widely, though the calculation is not as straightforward as it may first appear, and importantly, "avoided energy cost" means something different depending on whose perspective is being modeled. Box 6 describes the general formula for calculating avoided energy costs.

Box 6. Avoided Energy Cost Formula (General DER Form)

$$AEC = MC \times E_{DER}$$

Where:

AEC = Avoided energy cost ($)

MC = Marginal cost of energy ($/kWh)

E_{DER} = Expected output from the distributed energy resource (kWh) – e.g., expected solar generation, or, for storage, the amount of grid energy displaced by discharge

If marginal cost and expected output vary over time (e.g., hourly), the formula can be expressed as a summation:

$$AEC = \sum_{t=1}^{n} MC_t \times E_{DER,t}$$

Where:

MC_t = Marginal cost of energy in hour t ($/kWh)

$E_{DER,t}$ = Expected DER output (or avoided grid consumption) in hour t (kWh)

n = Number of hours in the period being evaluated (e.g., 8,760 for a full year)

As with the earlier formulas, both *MC* and E_{DER} should be clearly specified as to whose perspective they reflect (customer retail price vs. utility marginal/wholesale cost) and treated as forecasted, time-varying inputs rather than fixed constants.

From the customer's perspective, avoided energy cost is the amount of energy not purchased due to solar generation multiplied by the customer's retail price. This is generally the simpler of the two calculations, since the retail rate the customer would otherwise have paid is known or contractually defined.

Box 7. Avoided Energy Cost Formula (Customer Perspective)

$$AC_{customer} = AE \times P_{retail}$$

Where:

$AC_{customer}$ = Avoided energy cost to the customer ($)

AE = Avoided energy (kWh), the amount of energy not purchased from the grid due to solar generation or storage discharge

P_{retail} = Customer's retail price ($\frac{\$}{kWh}$)

If avoided energy and retail price vary by hour (e.g., under time-of-use rates), the formula can be expressed as a summation:

$$AC_{customer} = \sum_{t=1}^{n} AE_t \times P_{retail,t}$$

Where:

AE_t = Avoided energy in hour *t* (kWh)

$P_{retail,t}$ = Applicable retail price in hour t ($\frac{\$}{kWh}$): e.g., the time-of-use rate in effect during that hour

n = Number of hours in the period being evaluated (e.g., 8,760 for a full year)

From the utility's (or system's) perspective, avoided energy cost reflects the wholesale or marginal cost of energy the utility avoids having to generate or procure, not the retail price the customer avoids paying.

Box 8. Avoided Energy Cost Formula (Utility/Wholesale Perspective)

$$AC_{utility} = AE \times P_{wholesale}$$

Where:

$AC_{utility}$ = avoided energy cost to the utility ($)

AE = Avoided energy (kWh), determined using a model or historical regression of hourly solar production

$P_{wholesale}$ = Marginal wholesale energy price ($\frac{\$}{kWh}$), determined using a model or historical regression of hourly wholesale energy prices

If avoided energy and price vary by hour, the formula can be expressed as a summation across the forecast period:

$$AC_{utility} = \sum_{t=1}^{n} AE_t \times P_{wholesale,t}$$

Where:

AE_t = Avoided energy in hour t (kWh), from the solar production model/regression

$P_{wholesale,t}$ = Marginal wholesale price in hour t ($\frac{\$}{kWh}$), from the wholesale price model regression

n = Number of hours in the period being evaluated (e.g., 8,760 for a full year)

Because retail rates typically embed costs beyond marginal energy, including fixed infrastructure, transmission and distribution, and policy charges, the utility's avoided cost is generally lower than, and diverges over time from, the customer's avoided cost.

This distinction matters because the two calculations serve different purposes. Customer avoided cost drives the economics of a customer's decision to adopt solar, while utility avoided cost is what's relevant for utility system planning, rate design, and compensation mechanisms (e.g., net metering or avoided-cost tariffs).

In either case, the avoided cost is not fixed: it is likely to change substantially over time as the net load profile shifts. As solar penetration increases and shifts the timing of peak net demand, the hours in which solar generation displaces the most expensive marginal energy will also shift,

changing the effective avoided cost. Regional market dynamics must also be taken into account, since price formation, transmission constraints, and generation mix vary significantly by market. Periods of negative pricing add a further complication. During hours when wholesale prices go negative (often driven by high renewable output relative to demand), solar generation may have little or even negative avoided-cost value to the utility, which a simple retail-price-based formula does not capture. Any avoided-cost estimate, from either the customer side or utility side, should therefore be treated as a forecast requiring periodic updating, not a fixed parameter.

Retail rate design. The approach described above is employed in NEM programs in California,[98] New York,[99] Nevada,[100] South Carolina,[101] and Arkansas.[102] These studies see a range of avoided energy costs from $0.02–0.07 per kWh of solar energy produced.

For energy storage systems to reduce utility energy costs, the marginal costs avoided during storage discharge must be greater than the marginal cost increase during storage charging. Since storage technologies inherently consume more energy during charging relative to energy discharged (due to internal losses), the marginal cost rate must be lower during charging hours relative to discharge hours if utility cost savings are to be realized.[103] In other words, storage is most cost effective when time-of-use rates are designed to incentivize off-peak charging and on-peak discharging.

Grid services tariffs. For grid services programs, the avoided energy *cost* is computed in much the same way as described above, though each program defines the price component differently.[104]

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[98] Energy & Env't Econ., Inc., *2024 Distributed Energy Resources Avoided Cost Calculator Documentation* (Version 1b, Oct. 2, 2024), prepared for the Cal. Pub. Utils. Comm'n, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2024-acc-documentation-v1b_clean_posted_nowm.pdf

[99] Energy & Env't Econ., Inc., *The Benefits and Costs of Net Energy Metering in New York* (Dec. 11, 2015), prepared for the N.Y. State Energy Research & Dev. Auth. & N.Y. State Dep't of Pub. Serv., https://www.ethree.com/wp-content/uploads/2017/01/E3-NY-Legislative-NEM-Study-Report-121115-FINAL-SENT.pdf

[100] Energy & Env't Econ., Inc., *Nevada Net Energy Metering Impacts Evaluation 2016 Update* (Aug. 2016), https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf

[101] S.C. Office of Regulatory Staff, *2015 SC Cost Shift and Cost of Service Study* (2015), https://solar.sc.gov/sites/orssolar/files/Documents/learn-about-solar/documents/2015-sc-cost-shift-and-cost-of-service.pdf

[102] Ark. Pub. Serv. Comm'n, Order No. 28, Docket No. 16-027-R (2017) http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf

[103] Verdant Associates., LLC, *2023 Self-Generation Incentive Program Impact Evaluation* (2025), prepared for the Cal. Pub. Utils. Comm'n & SGIP Program Administrators, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2023_sgip_impact_evaluation.pdf

[104] **A note on terminology:** throughout this discussion, "avoided energy" refers to the physical quantity of energy (kWh) not consumed or purchased due to solar generation, while "avoided energy cost" refers to the dollar value of that avoided energy (avoided energy × price, in $/kWh or total $). The two are related but distinct, and should not be used interchangeably.

In New York's Value of Distributed Energy Resources (VDER), the avoided energy cost component uses NYISO's day-ahead market price as the price signal, applied to the solar system's metered or estimated output to determine the avoided energy cost.[105]

In Austin's Value of Solar rate, the avoided energy cost is calculated by weighting the day-ahead market price at the Austin Energy pricing node by the solar resource's generation profile. Specifically, each day's price is weighted by that day's share of annual solar output so that hours and days with higher solar production have proportionally more influence on the resulting average price. This weighted average price is then applied to the avoided energy to determine the avoided energy cost.[106] Using these methods, the resulting avoided energy cost rates come out to $0.07–0.10 per kWh in these programs.

Utility Procurements. In procurement programs, calculation of avoided energy costs is more difficult. One simple way to calculate this is to use the target capacity that the utility is seeking to procure and multiply that by the forecast energy prices to get a total avoided cost.

Box 9. Avoided Cost Formula (Procurement/Capacity-Based Approach)

$$AC = C_{target} \times P_{forecast}$$

Where:

AC = Avoided cost ($)

C_{target} = Target capacity the utility is seeking to procure (kW or MW)

$P_{forecast}$ = Forecast energy price ($/kWh or $/MWh, over the relevant period)

If the forecast price varies over time (e.g., by hour, month or season) the formula can be expressed as a summation *t:*

$$\mathrm{AC} = \sum_{t=1}^{n} \mathrm{C}_{\mathrm{target,t}} \times \mathrm{P}_{\mathrm{forecast,t}}$$

Where:

$C_{target,t}$ = Target capacity to be procured in period *t*

$P_{forecast,t}$ = Forecast energy price in period *t*

n = Number of time periods in the forecast horizon (e.g., 8,760 hours in a year)

[105] N.Y. State Energy Rsch. & Dev. Auth., *Value Stack Resources* (2026), https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Resources
[106] Austin Energy, *Value of Solar Rate* (2026), https://austinenergy.com/rates/commercial-rates/value-of-solar-rate

This approach differs from the avoided energy cost formula described earlier in that it starts from a procurement target (how much capacity the utility plans to acquire) rather than from modeled or metered avoided energy (how much energy is actually displaced by generation). As a result, it reflects the utility's planning-driven demand for capacity rather than the realized or forecasted output of a specific resource.

For instance, California's Demand Side Grid Support (DSGS) program uses prices from 2022 to 2024 as a proxy for future energy prices, and then computes an avoided capacity cost, rather than an avoided energy cost, based on the value of energy discharged from batteries enrolled in the program during periods of system need. Because the program's compensation is expressed in $/kW of enrolled capacity rather than $/kWh of energy discharged, the resulting value reflects the worth of having dispatchable capacity available, not simply the marginal cost of the energy itself. Based on these methods, Brattle estimates a value between $21 and $200 per kW of enrolled storage capacity.[107]

As described in Box 5, avoided *energy* cost is measured in $/kWh and reflects the value of displaced or discharged energy, while avoided *capacity* cost is measured in $/kW and reflects the value of having capacity available to meet demand (often during specific high-need hours or events). Programs like DSGS, which compensate based on enrolled capacity and dispatch during system need events, are more accurately characterized as avoided capacity cost mechanisms, even though the underlying price inputs are drawn from energy market prices.

Deployment Incentives. In the 2023 California Self-Generation Incentive Program (SGIP) evaluations, the avoided energy cost was up to $4 per kWh for storage paired with solar PV and up to $1 per kWh for standalone storage. Using the E3 Avoided Cost Calculator and CAISO Real-Time Local Marginal Price data, the SGIP evaluations compute avoided energy cost as the local marginal prices less the product of the power plant emissions impact and compliance costs.

If a storage device can be used to avoid the consumption of energy from the grid, that cost is avoided in the same way.

In practice, however, this calculation is less straightforward than the formula suggests, and it depends critically on whose perspective is being modeled. The avoided cost to a customer–measured against their retail rate–differs from the avoided cost to a utility or the broader grid, which is measured against wholesale or marginal costs and can diverge substantially depending on rate design, program structure, and market conditions. Any avoided-cost estimate should specify clearly whose cost is being avoided before the number can be interpreted or compared across programs.

The calculation is also inherently a forecasting exercise, not a fixed parameter. Both the "expected solar output" and the "marginal cost of energy" components rely on predictions about future market conditions. This includes how net load profiles shift as solar penetration increases, how regional market dynamics and price formation evolve, and how the growing frequency of negative

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[107] Hledik et al. *The Demand Side Grid Support Program: An Assessment of Scale and Value* (December 2025 Update). The Brattle Group. Prepared for Sunrun and Tesla Energy. https://www.brattle.com/wp-content/uploads/2025/12/The-Demand-Side-Grid-Support-Program-An-Assessment-of-Scale-and-Value-December-2025-Update.pdf

wholesale prices affects the value of displaced energy. Because these inputs change over time and vary by region and market structure, avoided cost estimates require periodic updating and should be treated as forecasts with uncertainty, not as stable, one-time calculations.

Avoided bulk capacity costs

Where avoided energy costs reflect the amount of money a utility saves from not having to use, operate, and maintain certain energy resources, avoided capacity costs reflect the long-term savings for a utility from not needing to maintain as much dispatchable capacity. Avoided capacity cost isn't limited to capacity a utility would otherwise have *built*. It can also include capacity a utility would otherwise have had to *retain or continue operating*, including existing generation that would otherwise need to be relied upon, refurbished, or life-extended to meet peak demand. If solar and storage reduce peak demand enough to allow an expensive existing facility to retire early, or avoid extending its operating life, that represents avoided capacity cost as well–and in some cases may be *larger* than the cost of new capacity, since aging or inefficient existing plants can be more expensive to operate and maintain than the levelized cost of new capacity.

Avoided capacity cost also has an important locational component. The same amount of avoided peaking capacity can have very different value depending on where on the grid it occurs. Capacity located in an area with binding transmission or distribution constraints, forecasted load growth, or limited local generation can avoid costly upgrades to that specific part of the system–such as substation or feeder upgrades, transmission reinforcement, or new local generation sited to relieve a constraint–and is therefore typically more valuable than equivalent capacity in an unconstrained area. As a result, avoided capacity cost is often calculated (or adjusted) at a more granular geographic level than avoided energy cost. Utilities or programs that pay for avoided capacity–including some locational or non-wires alternative programs–may apply location-specific capacity values (a "locational" or "deferral" value) rather than a single systemwide rate.

The "cost per unit of capacity avoided" term should therefore be understood broadly, and can be represented by any of the following depending on what specifically is being avoided:

- The cost of new capacity that would otherwise need to be built (e.g., a new peaker plant), typically approximated by its levelized cost of capacity
- The going-forward cost of retaining or extending the life of existing capacity that would otherwise be needed to serve peak demand
- The avoided cost of retiring existing capacity earlier than planned, if solar and storage displace enough peak demand to make that retirement feasible
- The avoided cost of local transmission or distribution capacity upgrades (e.g., substation or feeder upgrades) that would otherwise be needed to serve peak demand in a specific constrained area of the grid–where the value depends on the resource's location relative to the constraint, rather than on a systemwide capacity price

Box 10. Avoided Bulk Capacity Cost for a Utility

$$AC_{capacity} = C_{avoided} \times P_{avoided}$$

Where:

$AC_{capacity}$ = Avoided bulk capacity cost ($)

$C_{avoided}$ = Cost per unit of capacity avoided ($/kW or $/MW) – new capacity, retained/extended existing capacity, or capacity associated with early retirement, if applicable

$P_{avoided}$ = Peaking capacity avoided by solar plus storage resources (kW or MW)

Retail rate design. In an evaluation of NEM in New York by Energy and Environmental Economics, Inc.,[108] avoided capacity costs were computed using the Department of Public Service's Installed Capacity (ICAP) model, which incorporates the cost of new peaking capacity, operations and maintenance costs, and locational factors to determine the total cost of each new unit of capacity. The total avoided cost is this value multiplied by the expected peak load reduction from NEM technologies. Other NEM programs use a similar method, but use different models of capacity pricing. Notably, in Arkansas, the Net-Metering Working Group included a reduction in reserve capacity which is added to the total avoided cost as part of its program evaluation.[109]

Grid services tariffs. The Minnesota Value of Solar methodology, prepared by Clean Power Research for the Department of Commerce, computes avoided bulk costs due to distributed solar by first computing the economic value of comparing the cost of gas facilities, weighted by the difference between solar and gas efficiency and the difference in cost between gas resources.[110] That economic value is then multiplied by the effective load reduction due to the solar resources.

Utility Procurements. As part of an assessment of California's Demand Side Grid Support (DSGS) program, in which aggregators such as Sunrun and Tesla Energy enroll customer-sited batteries, the Brattle Group estimated bulk capacity costs by applying a range of capacity values to the demand reduction the enrolled batteries could reliably deliver during peak periods, as a fraction of their enrolled capacity, which is usually at or below the nameplate capacity. That load reduction, multiplied by the capacity cost, gives the avoided cost. [111]

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[108] Patel et al. (2015, December 11). *The Benefits and Costs of Net Energy Metering in New York*. Energy and Environmental Economics, Inc. (E3). https://www.ethree.com/wp-content/uploads/2017/01/E3-NY-Legislative-NEM-Study-Report-121115-FINAL-SENT.pdf

[109] Arkansas Public Service Commission, Net-Metering Working Group. (2017, September 15). *Joint Report and Recommendations of the Net-Metering Working Group*, Docket No. 16-027-R. http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf

[110] Minnesota Department of Commerce, Division of Energy Resources. (2014, April 1). *Minnesota Value of Solar: Methodology*. Prepared by Clean Power Research. https://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

[111] Hledik, et al. (2025, December 1). *The Demand Side Grid Support Program: An Assessment of Scale and Value* (December 2025 Update). The Brattle Group. Prepared for Sunrun and Tesla Energy. https://www.brattle.com/wp-

Deployment Incentives. The impact evaluation of California's SGIP program used the E3 avoided cost calculator to compute the avoided costs of solar, storage, and solar plus storage for both residential and nonresidential customer classes. The evaluation looks at the costs of charging and the benefits of discharging the batteries, so the capacity costs are reported in units of $/kWh. For nonresidential storage, the utility's avoided capacity costs for standalone storage were up to $8 per kWh and up to $12 per kWh for storage paired with solar PV; for residential systems, the utility's avoided capacity costs were up to $4 per kWh and up to $12 per kWh for standalone and PV-paired storage, respectively. [112]

Avoided distribution capacity costs

Avoided distribution capacity costs are notoriously challenging to compute, and are usually estimated or calculated directly by utilities. As a result, program evaluators and utility commissions often rely on utilities' calculations.

Box 11. Avoided Distribution Capacity Costs by a Utility

$$AC_{dist} = (C_{maintain} \times P_{avoided}) + (C_{new} \times C_{DER})$$

Where, with consistent units throughout:

AC_{dist} = Avoided distribution infrastructure cost ($)

$C_{maintain}$ = Cost per unit of **capacity** of maintaining existing distribution infrastructure ($/kW)

$P_{avoided}$ = Avoided peak **capacity** due to new distributed resources (kW)

C_{new} = Cost per unit of **capacity** of building new distribution infrastructure ($/kW)

C_{DER}= New DER **capacity** that would otherwise require new infrastructure to accommodate (kW)

If the underlying costs or avoided capacity vary by location or time period, the formula can be expressed as a summation across each relevant segment i (e.g., substation, feeder, or planning area):

content/uploads/2025/12/The-Demand-Side-Grid-Support-Program-An-Assessment-of-Scale-and-Value-December-2025-Update.pdf

[112] Verdant Associates., LLC, *2023 Self-Generation Incentive Program Impact Evaluation* (2025), prepared for the Cal. Pub. Utils. Comm'n & SGIP Program Administrators, Figures 4-160 and 4-166. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2023_sgip_impact_evaluation.pdf

$$AC_{dist} = \sum_{i=1}^{n} [(C_{maintain,i} \times P_{avoided,i}) + (C_{new,i} \times C_{DER,i})]$$

Where *i* indexes each distribution segment or location being evaluated, consistent with the locational nature of distribution capacity value discussed above.

Retail rate design. To determine distribution capacity costs, analyses of rate design generally focus on computing the marginal cost of adding distribution or performing distribution upgrades and estimating how much of those costs can be deferred by deploying DERs. In E3's benefit-cost analysis of NEM in New York, the computation relied on estimates provided by utilities in their Marginal Cost of Service Studies.[113] Similarly E3's evaluation of NEM in Nevada relied on the annualized costs of distribution upgrades and losses provided directly by utilities.[114] Then, the avoided distribution cost is the product of these costs and the amount that peak load is reduced due to DERs. The Arkansas Net-Metering Working Group estimated distribution system costs based on a regression against annual load growth to determine a per kW-yr estimate of marginal distribution costs, which comes to around $94 per kW-yr.[115] Then, using hourly profiles of residential loads and solar output, the model determines the solar contribution to demand reduction, and uses that to determine the avoided annual marginal distribution cost.

Grid services tariffs. Grid services tariffs compensate DERs for specific, defined services provided to the grid separate from, or in addition to, the energy value of their generation or self-consumption. Programs vary in how fully they embody this model; some, like New York's Value Stack, incorporate select grid-service elements within a broader tariff structure, while others are built around grid services compensation as their core design.

While most of the compensation under New York's Value Stack (the state's NEM successor tariff) reflects the energy and capacity value of a DER's output, two of its components function more like grid services compensation as defined above. Demand Reduction Value (DRV) pays projects specifically for their ability to reduce load during the grid's highest peak hours, based on utility-specific marginal cost studies. Locational System Relief Value (LSRV) provides an additional credit for projects located in high-value, constrained areas where DERs can provide immediate relief to localized distribution equipment. Unlike the Energy and Capacity components of the Value Stack, which compensate for the resource's generation or self-consumption, DRV and LSRV are structured as explicit, separate payments tied to defined service outputs (peak reduction and

[113] Patel et al. (2015, December 11). *The Benefits and Costs of Net Energy Metering in New York*. Energy and Environmental Economics, Inc. (E3). Prepared for the New York State Energy Research and Development Authority and the New York State Department of Public Service. https://www.ethree.com/wp-content/uploads/2017/01/E3-NY-Legislative-NEM-Study-Report-121115-FINAL-SENT.pdf

[114] Price et al. (2016, August). *Nevada Net Energy Metering Impacts Evaluation: 2016 Update*. Energy and Environmental Economics, Inc. (E3). Prepared for the Public Utilities Commission of Nevada. https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf

[115] Arkansas Public Service Commission, Net-Metering Working Group. (2017, September 15). *Joint Report and Recommendations of the Net-Metering Working Group*, Docket No. 16-027-R. http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf

locational relief, respectively). Because these elements are embedded within a broader NEM successor tariff rather than a standalone program, VDER illustrates how compensation for grid services can be incorporated into retail rate design, without the tariff as a whole qualifying as a "pure" grid services tariff. NYSERDA provides robust documentation for how these values are calculated.[116]

Voltage support: Virginia's virtual power plant pilot program, authorized under state law, directs the state's electric utility to establish tariffs that compensate enrolled DERs for a defined set of grid services, explicitly including demand reduction, voltage support, and emergency services, with pay-for-performance compensation mechanisms for each. Unlike a bundled retail-rate or NEM-successor tariff, compensation here is structured around discrete, contracted service categories that customers or aggregators can enroll in directly.[117]

Frequency regulation: At the wholesale level, regional grid operators such as ISO-NE (Independent System Operator-New England) and PJM (Pennsylvania-New Jersey-Maryland Regional Transmission Organization) operate ancillary services markets that compensate qualifying resources–increasingly including aggregated DERs, following FERC Order 2222–specifically for frequency regulation and reactive power/voltage support. ISO-NE's tariff, for example, compensates generating facilities for reactive supply and voltage control (VAR) service each month, separate from any energy market payments. These wholesale-market mechanisms represent grid services compensation in its most granular and technically explicit form: payment is tied strictly to a measured service rather than to energy delivered.[118]

Together, these examples illustrate a spectrum: VDER shows how grid-service elements can be layered onto a broader energy-compensation tariff, while BQDM, Virginia's pilot, and ISO-NE/PJM's ancillary services markets show grid services compensation operating as the primary or sole basis for payment — at the utility-retail level and the wholesale level.

Utility Procurements. Through solar and storage procurement, avoided costs can be estimated based on expected or realized deployment. In the Brattle Group's nationwide study, distribution costs are averaged based on reporting from a range of utilities. Then, the study models operations and costs of deploying 400 MW of VPP resources, and determines net avoided distribution costs of $52.5 per kW of installed capacity.[119]

In New York, Con Edison's Brooklyn Queens Demand Management (BQDM) program is one of the most established examples of a utility procuring distributed resources under a Non-Wires Solutions (NWS) framework.[120] Facing a projected $1.2 billion substation upgrade to relieve an

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[116] New York State Energy Research and Development Authority, *Value Stack Calculator*. https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Calculator?
[117] Virginia Code, (n.d) *§ 56-585.1:16. Virtual power plant pilot program*. https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:16/
[118] ISO New England. (n.d.). *OATT/ISO tariff frequently asked questions*. https://www.iso-ne.com/participate/support/faq/oatt-iso-tariff
[119] Hledik, et al. (2023, May). *Real Reliability: The Value of Virtual Power*. *https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf*
[120] Consolidated Edison Company of New York. (n.d.). *Non-wires solutions*. https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions

overloaded area of its Brooklyn and Queens network, Con Ed instead procured about 52 MW of peak demand reduction from a portfolio of energy efficiency, demand response, customer-sited generation, and utility-sited storage, at a total program cost of about $200M. One participating resource is a customer-owned microgrid at a 625-unit affordable housing complex in Brooklyn, which combines solar, a fuel cell, and lithium-ion battery storage. The framework specifically calculates the Net Avoided Cost[121] by comparing the cost of distributed energy resource procurement (demand response, batteries, efficiency) against the carrying costs of the deferred traditional utility capital project. In program evaluations, the utility also computes the amount of load reduced, which can be used with estimates of distribution costs to approximate avoided costs as well.[122] which now generates about $1 million in revenue during peak periods.[123] Per a 2019 filing of their avoided cost model, Con Ed expects to save around $125 - $150 / kW-yr on distribution costs due to BQDM.

Deployment Incentives. The Disadvantaged Communities Single-family Affordable Solar Homes (DAC-SASH) program in California is an incentive program for low-income households. As another California example, E3 used the California Avoided Cost Calculator and NLR's PVWatts to calculate cost effectiveness and net benefits for this incentive program.124 DAC-SASH employs an "expected performance-based buydown" model to determine the incentive level. In this case, the benefits associated with an incentive program are computed using a combination of other existing methods, as reported by Verdant Associates to CPUC.[125]

According to the 2023 SGIP impact evaluation, avoided distribution capacity costs for both standalone storage and storage paired with solar PV were approximately $1 per kWh of installed storage capacity in 2023. These values reflect the distribution capacity component of the CPUC's Avoided Cost Calculator (developed by E3) applied to each system's hourly charging and discharging.

Reduction in market prices

DERs can reduce aggregate net energy demand from utilities, which can in turn affect market prices which is a widely studied phenomenon in energy economics. A range of established methodologies exist for estimating these effects, capturing not only price impacts but also the distribution of resulting benefits and costs across market participants. One illustrative mechanism is the merit-order effect: because utilities generally dispatch their cheapest resources first, a

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[121] Lawrence Berkeley National Laboratory. (2021). *Locational value of distributed energy resources.* https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf
[122]New York State Department of Public Service, Public Service Commission. *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program*, Case 14-E-0302 (Matter No. 14-01390). https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800
[123] TD World. (n.d.). Non-wires alternatives: Non-traditional solutions to grid needs. https://www.tdworld.com/overhead-distribution/article/20972703/non-wires-alternatives-non-traditional-solutions-to-grid-needs
[124] Energy & Environmental Economics, Inc., *2024 Distributed Energy Resources Avoided Cost Calculator Documentation* (2024). https://www.cpuc.ca.gov/dercosteffectiveness
[125] Verdant Associates, LLC. (2026, April 14). *DAC-SASH 2022-2024 Evaluation Report*. Submitted to the California Public Utilities Commission (prepared for San Diego Gas & Electric on behalf of the CPUC, pursuant to Decision 18-06-027). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/solar-in-disadvantaged-communities/dac_sash_final_041426.pdf

reduction in net demand from DERs displaces the most expensive marginal resources, producing a price reduction roughly proportional to the change in net demand multiplied by the marginal price of the displaced capacity. This report does not attempt to fully apply that broader literature, but flags it as the appropriate reference point for future refinement of this benefit category, rather than treating the merit-order intuition as a standalone or novel method.

Estimating the reduction in market prices caused by DER deployment is a well-developed area of methodological economics research. It encompasses wholesale market price-formation modeling, demand elasticity estimation, and analysis of the distributional effects of price changes across different market participants. A full treatment of this literature is outside the scope of this document. Readers interested in the underlying methodology are directed to the studies specific to Demand Reduction in Price of Energy (DRIPE), which are referenced throughout this section (e.g., the AESC studies), and the broader academic and regulatory literature on wholesale electricity market price formation.

Retail rate design. Retail rates do not compensate customers for market price reductions directly, but they shape this benefit by influencing how much solar and storage is deployed and, through time-varying prices, whether storage discharges during the high-price hours when demand reductions have the greatest effect on market prices. Where export credits are set using an avoided cost of value of solar methodology, a DRIPE component can also be included explicitly.

Grid Services Tariffs. The New Hampshire Value of Distributed Energy Resources study calculated the DRIPE using wholesale values from the AESC 2021 study as the starting point.[126] Combining this with the DRIPE decay and converting to hourly and per kW values determines the reduction in market prices due to DERs.

In Connecticut's study on the value of distributed energy resources, prepared by CT DEEP and PURA, the addition of incremental DER generation impacts the load costs borne by Connecticut ratepayers relative to the base load costs without DERs. The value of reductions in wholesale energy prices as a result of adding DERs, or, the unitized value of energy DRIPE represents the forecasted annual Connecticut net cost-to-load divided by the annual projected DER generation based on the incentive offered. In the Connecticut example, the DRIPE benefit ranges from $5 to $5.68 per MWh.[127]

Maryland's Value of Solar study uses modeling to approximate the formation of hourly energy market clearing prices throughout PJM and neighboring regions.[128] The market simulation, relying on a difference analysis, provides estimates of both avoided energy **cost** and market price

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[126] New Hampshire Public Utilities Commission, *Value of Distributed Energy Resources (VDER) Study*, referencing Demand Reduction in Price of Energy (DRIPE) values derived from the *Avoided Energy Supply Components (AESC) 2021* report.
[127] Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Agency, *Distributed Energy Resources in Connecticut*, July 2020. https://psc.ky.gov/pscecf/2020-00174/dspenard%40strobobarkley.com/03162021072217/2021.03.16_kyseia_inskeep_2_table_1_footnote_22.pdf
[128] Maryland Public Service Commission, *Costs and Benefits of Solar: Draft for Stakeholder Review (2023)*, https://psc.maryland.gov/wp-content/uploads/MD-Costs-and-Benefits-of-Solar-Draft-for-stakeholder-review.pdf

response benefits–both measured in dollar terms ($/MWh), not as physical energy quantities.[129] Under the study's Reference Scenario, the market price response ("energy market price effect") benefit ranges from approximately $0.20 to $1.20 per MWh, varying by utility service territory (BGE, DPL, PEPCO, and Potomac Edison) and by year across the 2019–2028 study period.

Utility Procurements. In a valuation study of distributed solar resources in Maine, prepared by Clean Power Research in 2015, researchers adapted the AESC DRIPE methodology to consider solar capacity. Normally these methods look at load reductions to determine changes in prices, so are more suited to energy efficiency. However, distributed solar and storage can functionally reduce on-site load, leading to a similar demand reduction impact, and having calculable price impacts as well. In the Maine study, the researchers adapt DRIPE load reductions for energy efficiency by applying the effective load carrying capacity of the procured resources. This acts as a modifier on the load reductions and can be used to compute price impacts based on the amount of procured distributed solar and storage.[130]

Deployment Incentives. In Massachusetts's Mass Save energy efficiency program, reductions in market prices are computed using DRIPE, where avoided-energy DRIPE benefits are the product of avoided energy and avoided-energy DRIPE as presented in AESC 2018.[131]

Increased host customer resilience

While there is no standard or universally accepted method for quantifying resilience benefits, analysts typically estimate them using established reliability metrics such as the value of lost load (VoLL), loss of load expectation (LOLE), or interruption cost estimates, combined with the likelihood that a customer with DER will not lose power. When applying published VoLL figures, it is important to recognize that they are typically calculated as an average across industrial, commercial, and residential customers. Because residential customers generally have a substantially lower value of lost load (VoLL) than industrial or commercial customers, using a blended or system-average VoLL figure can significantly overstate the resilience benefit for residential DER applications. Where possible, customer-class-specific VoLL estimates rather than

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[129] Note: Throughout this section, program and utility filings frequently use "avoided energy" as shorthand for what this document more precisely terms "avoided energy cost" — the dollar value of energy not purchased or generated (avoided energy × price), rather than the physical quantity of energy itself (kWh or MWh). This labeling convention is common across the source materials cited here–including Maryland's Value of Solar study, which reports its "Avoided Energy" benefit component in $/MWh–and is not unique to any single program or jurisdiction. Readers should verify the units (kWh/MWh vs. $/kWh or $/MWh) when comparing "avoided energy" figures across sources, since the same term may refer to either the physical or monetary quantity depending on the source's convention.

[130] Maine Public Utilities Commission. (2015) *Maine Distributed Solar Valuation Study*. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4568-WED-Ex6-MaineSolarReport%2811-23-15%29.pdf

[131] Mass Save's program administrators (including National Grid, Eversource, and other Massachusetts utilities) use AESC-based avoided costs — including energy DRIPE and capacity DRIPE — in their program cost-effectiveness screening. *See* Avoided Energy Supply Components in New England: 2018 Report, prepared for the AESC 2018 Study Group by Synapse Energy Economics et al. (March 30, 2018), Chapter 9 (DRIPE); *see also* Synapse Energy Economics, *AESC 2021: Utility System Benefits From Demand Response Programs* ("The Avoided Energy Supply Cost (AESC) studies provide avoided energy, capacity, capacity DRIPE, energy DRIPE, transmission, distribution, and reliability costs that are used by National Grid ... to assess the cost-effectiveness of its energy efficiency programs.") https://www.synapse-energy.com/aesc-2021-utility-system-benefits-demand-response-programs

a single averaged value should be used, particularly for programs or assessments focused primarily on residential customers.[132]

Together, these metrics provide different but complementary ways of quantifying the economic value of reliability, and the choice of metric can meaningfully affect the resulting resilience benefit estimate.

Retail rate design and Grid Services Tariffs. These have only a modest indirect effect on this benefit.

Utility Procurement. In a nationwide study of VPP procurement, Brattle computed a number of benefits of VPP programs including resilience. Their methodology assumed the procured battery provides 22.5 kWh of outage relief per event, over two events per year, for a total of 45 kWh per BTM storage participant. Using a value of lost load estimate of $1,000/MWh, this is valued at $45 per BTM storage participant per year. Applied across the relatively small share of VPP participants enrolled in battery storage–Brattle assumed only 1% of the utility's 1.75 million residential customers were eligible for the BTM battery program, with 20% of those eligible customers participating (approximately 3,500 participants)--the resilience benefit totals approximately $0.16 million per year for the full VPP program. Spread across Brattle's full 400 MW VPP procurement, this resilience benefit comes out to approximately $0.40 per kW-year.[133]

Deployment Incentives. Solar-plus-storage incentives, such as California's SGIP, illustrate how a single customer benefit can be calculated using two entirely separate compensation mechanisms depending on the technology.

The storage portion is compensated through a capacity-based incentive, a fixed dollar rate per Wh-AC of installed storage capacity, which varies by budget category (e.g., $1.00/Wh for Equity Resiliency, $0.85/Wh for Equity) and can include additional adders, such as the $0.15/Wh resiliency adder available to nonresidential customers with critical facility or infrastructure needs. This rate is set administratively by the program and does not derive from the avoided-cost or DRIPE-based methodologies discussed elsewhere in this document.

The solar portion of a paired system, by contrast, is not compensated through SGIP at all. Solar export value in California is instead set separately through the state's Net Billing Tariff, which

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[132] Value of Lost Load (VoLL) is a dollar-per-kWh (or dollar-per-unserved-kWh) estimate of what customers are willing to pay to avoid an outage, or equivalently, the cost they bear when service is interrupted. It is often derived from customer surveys or revealed-preference studies and varies significantly by customer class, outage duration, and time of day. Loss of Load Expectation (LOLE) is a probabilistic reliability metric, typically expressed in expected hours (or days) per year, representing the anticipated frequency with which available generation and grid resources will be insufficient to meet demand. LOLE is commonly used in resource adequacy planning to determine how much capacity a system needs to maintain an acceptable reliability standard (e.g., "1 day in 10 years" is a common LOLE planning target). Interruption Cost Estimator (ICE) is a calculator tool, developed by Lawrence Berkeley National Laboratory, that estimates the economic costs of power interruptions to customers based on inputs such as customer class, geographic region, outage duration and timing, and season. It is widely used by utilities and regulators to translate reliability metrics into monetized customer costs.

[133] Hledik, et al. (2025, December 1). *The Demand Side Grid Support Program: An Assessment of Scale and Value* The Brattle Group. Prepared for Sunrun and Tesla Energy. https://www.brattle.com/wp-content/uploads/2025/12/The-Demand-Side-Grid-Support-Program-An-Assessment-of-Scale-and-Value-December-2025-Update.pdf

compensates exported solar energy based on hourly avoided-cost value. As a result, evaluating the total customer benefit of a paired solar-plus-storage system under this program requires combining two independently-determined compensation streams–a fixed capacity-based storage rate and an avoided-cost-based solar export rate–rather than a single unified benefit calculation.

Reduced hydropower ramping benefits

This benefit is challenging to quantify, but some studies suggest an approximate method that is proposed here. Reduced hydropower ramping is also ecologically significant, as rapid changes in flow and water levels caused by ramping events can strand or displace fish—particularly juvenile salmonids—and disrupt spawning habitat downstream of hydropower facilities. Estimating that a ramping event has similar impacts and costs as a start/stop cycle, compute the cost of a marginal start/stop cycle for a particular hydropower facility. This is related to the operations and maintenance costs for ramping. Assuming that a hydropower facility must ramp during a morning or evening peak, estimates of how much a peak can be shaved by some deployed DER technology, such as solar, storage, or solar + storage, can be made. The ramping event is reduced in magnitude and duration by how much the peak load is reduced, and that factor applies a reduction to the ramping cost. Additionally, some studies suggest that increased DER penetration may lead to increased ramping events, though they may be shallower, in order to respond to the variability of some resources. Another study computes the optimal ramp rates and times to support DER deployment. Overall, this points to a highly complex methodology for estimating the impact on hydropower operations from increased DERs, with storage being a key element in realizing the benefits. A summary of additional considerations related to hydropower ramping is found in Appendix H.

Improved economic wellbeing (distributional impacts)

A strong disparity still exists in energy affordability and access at the community level. Energy affordability studies show that an energy burden (energy spending divided by income) above 6% can put a household at high risk of not being able to afford their energy needs. This includes the energy required to maintain a comfortable indoor temperature and operate essential electrical appliances and medical equipment. According to studies, a quarter of U.S. households pay more than 6% of their income on energy bills, with 13% of households paying more than 10%.[134]

Inequity is worsened when considering historically disadvantaged communities; for example, the majority of African American census tracts in the U.S. face significant energy burden. Moreover, according to past surveys, the energy burden on a household is not a one-time event, but rather a persistent problem for low- to moderate-income (LMI) households.[135] In severely energy-burdened households, this perpetual cycle can be difficult to break. In such cases, households may face a

[134] Homsy, G. et al. Energy Burden: Exploring the Intersection of Race, Income, and Community Characteristics across the United States. Energy Research & Social Science 2025, 127, 104207. https://doi.org/10.1016/j.erss.2025.104207
[135] Konisky, D. et al. The Persistence of Household Energy Insecurity during the COVID-19 Pandemic. Environ. Res. Lett. 2022, 17 (10), 104017. https://doi.org/10.1088/1748-9326/ac90d7

choice of "Heat or Eat?", meaning, a choice between meeting their energy needs or securing other necessities.[136,137]

Programs such as the Low-Income Home Energy Assistance Program (LIHEAP) have tried to alleviate household energy burden. However, LIHEAP and similar programs are severely underfunded relative to the scale of need, and annual appropriations reach only a small fraction of eligible households and cover only a portion of the energy burden for those they do serve, leaving the vast majority of the underlying gap unaddressed. Moreover, given the persistent, recurring nature of energy burden, it cannot be resolved through one-time or episodic assistance; sustained, adequately funded efforts are needed instead.

With the decreased cost of implementing solar, it is possible to provide relief to energy burdened households by assisting their acquisition of solar generation systems. Although these systems have high capital costs, they can create a long-term decrease in utility bills.[138] Moreover, with the inclusion of storage, households will be able to avoid paying for energy used during more expensive peak hours in addition to having resilient energy access.

A study conducted in rural Australia showed that rooftop solar PV mitigated household energy insecurity and consequently reduced the incidence of involuntary "self-disconnection" from an inability to pay.[139] The study highlighted observable reductions in monthly energy costs ranging from A$84 to A$195.[140]

Another study examined whether rooftop solar reduces energy insecurity among U.S. households, using a national sample of solar and non-solar households, most of them low- to moderate income. Among non-solar households in the sample, 13.3% reported being unable to pay an electricity bill and 8.0% had received a disconnection notice for nonpayment. Many more reported coping strategies: 74.1% had cut back on electricity use to save money, 22.6% had reduced or gone without basic necessities, and 33.1% said they "always" or "often" kept their homes at an uncomfortable temperature. The study found that installing rooftop solar substantially reduced households' experience of energy insecurity. [141]

The study results suggest that the implementation of rooftop solar can significantly improve a household's likelihood to pay its electricity bills, while simultaneously decreasing the likelihood of disconnection notices, skipping other necessities, or keeping homes at uncomfortable

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[136] Ibid.
[137] Bhattacharya, J. et al,. (2003). Heat or eat? *Cold-weather shocks and nutrition in poor American families.* American Journal of Public Health, 93(7), 1149–1154. https://doi.org/10.2105/AJPH.93.7.1149
[138] Cook, J. et al Reducing Energy Burden with Solar: Colorado's Strategy and Roadmap for States; NREL/TP--6A20-70965, 1431421; 2018; https://doi.org/10.2172/1431421
[139] Riley, B. et al Connected: Rooftop Solar, Prepay and Reducing Energy Insecurity in Remote Australia. Australian Geographer 2023, 54 (3), 325–346.
[140] Ibid.
[141] Yozwiak, M. et al. The Effect of Residential Solar on Energy Insecurity among Low- to Moderate-Income Households. Nat Energy 2025, 10 (5), 569–580. https://doi.org/10.1038/s41560-025-01730-y

temperatures.[142] The study also highlighted that households with solar spent $65 less per month on electricity, 36% lower than the control mean ($183). The study also reported:

> *"We find that the installation of solar panels leads to large decreases in households' experience of energy insecurity. Solar households are 44% less likely to report being unable to pay their electricity bills, 46% less likely to receive a disconnection notice from their electricity provider, 15% less likely to reduce their energy consumption to save money on energy costs, 34% less likely to forgo necessary expenses to pay an energy bill and 20% less likely to keep the home at an uncomfortable temperature. These effects are robust to different model and sample specifications. We further find that the effect of solar spills over from electricity and improves a household's ability to pay their natural gas bills."*[143]

Job creation & economic/workforce development

Evidence on the workforce benefits of rooftop solar and storage for environmental justice communities in the U.S. is limited and comes mainly from California. Evaluations of California's low-income solar programs, such as DAC-SASH, which requires job training on installations, report that trainees and volunteers were more likely to work in the solar industry afterward, though evaluators note that data limitations prevent reliable measurement of long-term job outcomes. Labor research has also found that rooftop solar jobs in California tend to pay less than utility-scale solar jobs, which are more often unionized. Studies from Europe provide additional evidence on local employment effects, but differences in labor markets and policy mean their findings may not transfer directly to Washington.[144]

A 2024 case study from Spain[145] found that rooftop solar projects positively impact local employment firms during the construction phase, but have a weak effect on decreasing unemployment due to hiring outside of local communities. In Washington State, encouraging local firms to hire within the local community will increase employment benefits locally.

A 2011 case study from Greece[146] created a model that quantified employment benefits associated with rooftop solar installations. The model outputs the "[labor-years] per TWh of electricity generated or per MW of installed capacity." The model includes the economic valuation of social gains associated with new employment, including income, and improvement in health related consequences associated with unemployment i.e. decreased stress and substance use. This study was written in August 2011 when Greece's unemployment rate was 18%,[147] meaning that there was

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[142] Ibid.
[143] Ibid.
[144] Zabin, C. et al. (2020). *Putting California on the High Road: A Jobs and Climate Action Plan for 2030.* UC Berkeley Labor Center. Prepared for the California Workforce Development Board. https://laborcenter.berkeley.edu/putting-california-on-the-high-road-a-jobs-and-climate-action-plan-for-2030/
[145] Fabra et al. (2024) *Do renewable energy investments create local jobs?* Journal of Public Economics. https://doi.org/10.1016/j.jpubeco.2024.105212
[146] Tourkolias, S. Mirasgedis, (2011) *Quantification and monetization of employment benefits associated with renewable energy technologies in Greece,* Renewable and Sustainable Energy Reviews, https://doi.org/10.1016/j.rser.2011.02.027.
[147] Macrotrends. (n.d.). Greece unemployment rate. https://www.macrotrends.net/global-metrics/countries/grc/greece/unemployment-rate

a surplus of available labor and the employment benefits would be larger than those in Washington State which has a 5% unemployment rate.[148]

Cost Categories

Bulk and distribution system cost factors

Increased interconnection of resources incurs a cost, and increased net electricity consumption also incurs distribution costs; storage likely increases net consumption during charging times, (unless it charges entirely from BTM resources). As a result, the addition of distributed resources does increase some costs.

An hourly dispatch model may be used to quantify the impacts on system efficiency from distributed generation. Such models use the generating profiles of distributed generators to quantify the extent to which inflexible central steam-powered generators will be forced to operate at a less efficient (MWh/MMBtu) level of output. When this occurs, the cost impact will be reflected in the model's energy price.[149]

In a study prepared for the Public Utilities Commission of Nevada, E3 (Energy and Environmental Economics) estimates distribution system cost factors by including a sensitivity analysis in which it is assumed that NEM systems are not efficient enough to defer distribution upgrades; i.e., the distribution costs are not avoided and the utility pays the full cost.[150] NV Energy North and South provided annualized fixed distribution costs ($107.11/kW-yr and $55.63/kW-yr) by conducting a marginal cost of service study.[151] Marginal cost of service studies can be used to estimate the value of adding a marginal unit of generation, transmission, or distribution, and are how utilities arrive at these cost factors. In particular, utilities use models, forecasts, and historical hourly load data to determine the "probability of peak" cost responsibility factors, which are then used to reflect the cost and causation of the need for upgrades.[152]

Similarly, generation capacity costs are allocated using forecasted hourly loss of load probabilities, which are usually determined by production cost models.

In its evaluation of NEM, the Arkansas Net-Metering Working Group calculates Entergy Arkansas's marginal distribution costs using a regression fit to historical peak load growth vs. distribution expenditures. The data come from FERC Form 1 over the 18 years 1996 to 2013. This regression

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[148] Macrotrends. (n.d). Washington State unemployment rate. https://www.macrotrends.net/4199/washington-unemployment-rate
[149] Synapse Energy Economics, Final Report on Distributed Energy Resource Valuation (n.d.), https://www.synapse-energy.com/sites/default/files/Final%20Report.pdf.
[150] Nevada Public Utilities Commission, Docket No. 16-08014, Investigation into Distributed Energy Resources (2016), https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf
[151] Nevada Governor's New Energy Industry Task Force, Cost of Service Study v2 (2016), https://www.energy.nv.gov/siteassets/content/programs/5_NewEnergyTaskForceCOSSv2.pdf
[152] NV Energy, Sierra Pacific Power Company General Rate Case, Volume 8 – Electric (2024), https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/recent-regulatory-filings/north/grc/electric/2024-elec-grc/SPPC-Vol-08-Elec-2024-GRC.pdf.

gives cumulative distribution costs as a function of load growth, and a marginal distribution cost of $93.98 / kW-yr.[153] The calculation of the avoided costs is described above.

Taken together, these methodologies illustrate a consistent pattern across every benefit and cost factor examined in this section: quantification is possible, but it is neither standardized nor mechanically simple. Each factor requires choices, whose perspective to value from, what price signal to apply, how to translate qualitative outcomes like resilience or ecological harm into dollar terms, and those choices vary by jurisdiction, by mechanism, and often by data availability. Where established methodologies exist, as with avoided energy costs, the underlying formulas are well documented but still diverge meaningfully depending on whether the customer's or the utility's perspective is being modeled. Where methodologies are still emerging, as with hydropower ramping reduction or job creation, this section proposes reasonable approaches drawn from analogous studies rather than pointing to settled Washington-specific practice. This factor-by-factor foundation supports the comparative analysis that follows in Sections VIII and IX, which characterize how each policy mechanism realizes these benefits and incurs these costs, and with what distributional consequences for Washington ratepayers.

[153] Arkansas Public Service Commission, *Docket No. 16-027-R, Order No. 28* (2017), http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf.

VIII. CHARACTERIZATION OF POLICY MECHANISMS BY REALIZED BENEFITS

Section V described the four primary policy mechanisms through which the deployment of distributed solar and storage is encouraged. The preceding section identified the representative set of benefit and cost factors that anchor this report. This section brings those threads together, examining for each benefit factor how effectively the four mechanisms tend to realize it, under what conditions, and with what distributional consequences for Washington ratepayers and communities.

The characterizations presented here are qualitative rather than quantitative, grounded in state-level examples and the Phase 2 literature review. A foundational distinction organizes the analysis: the difference between solar-only installations and those including battery energy storage. A solar-only behind-the-meter (BTM) installation is passive and non-dispatchable; its ability to realize any benefit is a function of how well its generation profile coincides with the conditions under which that benefit can be captured. A storage-enabled installation is dispatchable, and therefore its operational behavior can be shaped by rate design, grid services compensation, procurement contracts, and other policy instruments.

Each benefit factor is analyzed in three parts: 1) a characterization for solar-only installations across the four mechanisms (for historical contrast), 2) a parallel characterization for storage-enabled installations, and 3) an equity perspective examining the distributional incidence of the benefit and the degree to which current or proposed mechanism designs reach populations with the greatest need. Washington State's statutory equity obligations—under CETA, the CCA, and the HEAL Act—require that this distributional analysis be integrated into, not appended to, the effectiveness analysis. Equity considerations are therefore treated as a primary dimension of each factor's analysis, not a secondary addendum.

Box 12. Who benefits from solar plus storage?

Increased deployment of solar plus storage has the potential to reduce environmental burdens on highly impacted communities by reducing emissions from fossil fuel generation, with much of the public health benefit going to the most burdened communities simply because of their historical overexposure. The equitable distribution of economic and resiliency benefits is much harder to predict simply from the increased deployment of solar + storage. Who benefits is largely dependent on where and how solar plus storage is implemented, which is further dependent on the policies and regulations that enable its growth.

Pathways to distributional impacts of solar plus storage include mechanisms for paying solar + storage adopters for providing support to grid stability through grid services tariff programs. Individual households are not normally able to participate in grid services markets but can be part of a Virtual Power Plant (VPP), which aggregates multiple small DERs enabling households and small businesses to participate.

Without policies that consider equity, these affordability and resilience benefits will only accrue to wealthier households who can afford up-front solar plus storage investments. Multiple states have

VPP programs with equity components considered, including California, Connecticut, Georgia, Hawaii, Illinois, Massachusetts, Washington, and Vermont.[154] Most of these provide up-front funding for targeted populations (e.g., LMI, outage prone, and medically vulnerable customers). Some include zero interest loans. Others include rebate adders for targeted populations, but under these methods, solar plus storage may remain inaccessible due to up-front cost barriers.[155]

The evidence behind the equity analysis varies more from factor to factor than the evidence behind the effectiveness analysis. Some factors are backed by a substantial body of evidence. For others, research is not as robust, or no Washington-specific evidence exists. Italicized research notes throughout the section identify where those gaps occur.

Avoided Energy Costs

Avoided energy costs represent the reduction in wholesale energy procurement expenditures attributable to distributed solar and storage generation. The central variable governing their realization is the degree to which the mechanism aligns the timing of distributed resource output with periods of highest marginal energy cost.

Solar-Only Installations

Retail Rate Design. Under flat-rate NEM, avoided energy costs are realized through on-site solar consumption displacing retail purchases, but export compensation does not differentiate by time of generation, generally producing misalignment with wholesale energy value. Time-of-use (TOU) rates improve alignment but cannot overcome the fundamental non-dispatchability of solar generation.

TOU rate design can, however, influence *when* solar output occurs, even without dispatchability, by shaping installation-time decisions rather than real-time operation. Because system orientation is fixed at installation, a TOU rate with a late-afternoon or evening peak period creates an incentive for customers and installers to favor west-facing panel orientations over the traditional south-facing default. West-facing arrays shift the shape of a system's generation profile later into the day—trading some peak midday output for greater output during the late-afternoon and evening hours when TOU peak pricing (and, not coincidentally, net system load) is highest. This does not resolve solar's non-dispatchability in real time, but it is a rate-design lever that can improve the

[154] Virtual Power Plant Programs Summary Table. (n.d.). *Clean Energy States Alliance*. Retrieved May 18, 2026, https://www.cesa.org/projects/energy-storage-policy-for-states/virtual-power-plant-programs-summary-table/

[155] **California**: SGIP-Reserves funding for "low income, outage-prone and medically vulnerable residential customers, and for commercial and municipal facilities serving disadvantaged communities, Indian territories, or low income communities; or located in outage- and fire-prone areas, and providing essential or emergency services." Sunrun Brightbox VPP-10% to LMI. **Colorado**: Up-front incentive and annual participation incentive for participating in control events. **Connecticut**: Rebate adders offered for low income and underserved residential customers. **Georgia**: Low to moderate income residential customers and commercial customers in the MUSH sector receive higher upfront incentives. **Hawaii**: LMI adder doubles the upfront incentive. **Illinois**: LMI higher upfront payment and rebate payment. **Massachusetts**: Free and discounted equipment for LMI customers; zero-interest financing. **Rhode Island**: Zero interest loans. **Vermont**: LI customers receive a free battery; MI customers pay approx. $15/month. **Washington**: Enhanced incentives for income-eligible and home health customers; additional funds for customers facing frequent outages.

alignment between when a given installation generates and when that generation is most valuable, without requiring any change to the underlying technology. Some utilities and states have adopted a west-facing orientation incentive or bonus more directly, structured as a deployment incentive adder rather than a rate-design feature, for the same underlying purpose.

Grid Services Tariffs. Grid services compensation at time-differentiated rates—as under New York's VDER tariff, which uses NYISO day-ahead hourly LMPs as the energy value component—more accurately reflects the avoided energy cost of solar exports than flat-rate NEM.[156] However, alignment improvement is a matter of measurement accuracy rather than increased actual benefit delivery: the solar resource cannot shift output to higher-value periods.

Utility Procurements. Not applicable to solar-only BTM resources. Utilities generally do not conduct competitive solicitations for non-dispatchable solar generation whose output flows primarily to the host customer.

Deployment Incentives. Incentives do not directly realize avoided energy costs; they reduce the capital barrier to installation, enabling the benefit to be realized through the applicable retail rate structure. The avoided energy cost per installed kilowatt is a function of rate design quality, not incentive program design.

Storage-Enabled Installations

Retail Rate Design. Under a well-designed TOU retail rate structure in which both on-site consumption savings and export compensation are time-differentiated to approximate wholesale costs, a storage-enabled installation can realize nearly the full potential avoided energy cost benefit, limited only by roundtrip efficiency losses. California's Avoided Cost Calculator (which provides detailed hourly avoided cost schedules used to set export compensation rates) represents current best practice. The key design requirement is that both the import rate and the export compensation rate reflect time-varying wholesale costs; flat rates eliminate the economic motivation for temporal arbitrage entirely.

Grid Services Tariffs. Grid services tariffs at time-differentiated rates effectively direct storage discharge toward high-value energy periods for exported energy. Energy consumed on-site is governed by the retail rate, not the grid services tariff. Effective realization of avoided energy costs from storage therefore requires both mechanisms in combination.

Utility Procurements. Procurement contracts are typically structured around capacity or local reliability services rather than energy arbitrage. Storage dispatched under procurement obligations may not be operated in a manner that maximizes avoided energy costs; energy savings are a co-benefit of capacity-oriented dispatch rather than a primary procurement objective.

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[156] N.Y. State Energy Research & Development Authority, Value Stack Resources (2026), https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Resources

Deployment Incentives. Incentives for storage do not directly realize avoided energy costs. The avoided energy cost of an incentivized storage installation depends entirely on the retail rate design and grid services compensation in effect for the host customer.

Equity Perspective

Avoided energy costs translate into ratepayer benefits primarily through their effect on electricity rates. Rate reductions proportional to consumption typically provide larger absolute savings to higher-consumption (higher-income) customers because they tend to use more energy, though the proportional benefit relative to income may be greater for low-to-moderate-income (LMI) households. The geographic pattern of distributed resource deployment affects the distributional incidence of avoided energy cost benefits: if solar installations are concentrated in higher-income households, the savings accrue to these adopters, while the costs to operate the grid fall on non-adopters, as noted in the previous cost shift discussions. TOU rate designs that more closely reflect time-based energy delivery costs may create hardship for LMI customers and renters who cannot readily shift consumption out of high-cost TOU periods, even as those same rate designs improve the alignment between compensation and time-based value discussed above. Low-income rate assistance programs–such as California's CARE and FERA discounts–can partially offset electricity rate increases for high-burden households but do not address the questions of equity in upstream deployment of solar + storage.

Research note: Washington-specific data on the distributional incidence of avoided energy cost benefits across income groups is limited. Analysis calibrated to Washington's rate structures, load profiles, and solar deployment patterns would strengthen the equity dimension of this factor's assessment.

Avoided Bulk Capacity Costs

Avoided bulk capacity costs are the savings from not having to buy as much backup generation capacity, because distributed solar and storage help meet demand during the hours when the system is most at risk of running short. What matters is how well these resources perform during those specific peak-risk hours--not how much energy they generate on average.

Solar-Only Installations

Solar-only effective load-carrying capability (ELCC) of distributed resources is inherently limited and declines as penetration increases. As solar deployment shifts net peak demand from midafternoon to early evening, when solar output is declining or zero, the coincidence between solar generation and system peak periods diminishes. This is a fundamental physical constraint that mechanism design cannot overcome.

Retail Rate Design. Where retail rates include demand charges or capacity components reflecting peak period cost causation, a solar installation generating during peak periods realizes avoided capacity cost implicitly. Flat-rate NEM provides no such signal. Declining ELCC as solar penetration grows means this benefit diminishes over time regardless of rate structure.

Grid Services Tariffs. Capacity value components–such as the ICAP value in New York's VDER[157] tariff–compensate solar-only installations for their ELCC contribution. This provides more accurate measurement than flat NEM but does not change the underlying ELCC of the resource.

Utility Procurements. Use of this mechanism is rare to nonexistent for solar-only BTM resources. Solar ELCC values are too low and too variable to support reliable capacity procurement contracts.

Deployment Incentives. These incentives do not specifically target bulk capacity realization. The capacity value of an incentivized solar-only installation depends on the host customer's rate structure and the system's generation profile.

Storage-Enabled Installations

Storage is dispatchable and can be directed to discharge during capacity-critical periods regardless of concurrent solar conditions, enabling substantially higher and more reliable capacity value realization than solar-only resources.

Retail Rate Design. TOU rates with on-peak periods aligned with bulk system capacity needs create strong dispatch incentives for storage during capacity-critical hours. Misalignment between static TOU on-peak periods and actual system peak conditions reduces capacity value realization.

Grid Services Tariffs. Programs specifically targeting capacity, such as Massachusetts' ConnectedSolutions demand response program, which dispatches enrolled storage during utility-declared capacity events, can direct storage to discharge during the precise hours when capacity value is highest.[158] These programs achieve higher realization than retail rate design because they operate on event-specific dispatch signals rather than static schedules.

Utility Procurements. VPP procurement contracts with capacity as the primary service, such as Sunrun's resource adequacy VPP agreement with SCE,[159] can realize nearly the full ELCC potential of the contracted fleet. Competitive procurement should in principle reveal the minimum compensation at which aggregators can profitably deliver required capacity, improving cost-effectiveness as the market matures.

Deployment Incentives. Incentive programs that condition payments on enrollment in qualifying demand response or grid services programs, as Massachusetts' SMART[160] program does, create a structural link between deployment incentives and capacity-relevant operation. But the presence of an operational requirement does not, by itself, guarantee the intended outcome—the

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[157] N.Y. State Energy Research & Development Authority, *Value Stack Resources* (2026), https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Resources

[158] ConnectedSolutions. *Program Materials for ConnectedSolutions for Commercial / Industrial Customers*. https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-programmaterials.pdf

[159] Sunrun Inc. (2020, November 19). *Sunrun Signs Virtual Power Plant Agreement with Southern California Edison* [Press release]. https://investors.sunrun.com/news-events/press-releases/detail/221/sunrun-signs-virtual-power-plant-agreement-with-southern

[160] Massachusetts Department of Energy Resources. (September, 2025) *225 CMR 20.00: Solar Massachusetts Renewable Target (SMART) Program*. https://www.mass.gov/regulations/225-CMR-2000-solar-massachusetts-renewable-target-smart-program

requirement must also be well calibrated to that outcome. California's Self-Generation Incentive Program (SGIP)[161] illustrates a different operational-conditioning approach, tying incentive payments to greenhouse gas emissions performance rather than demand response enrollment. This history is instructive on calibration: SGIP's original operational requirement was a simple round-trip efficiency threshold used as a rough proxy for emissions performance, but evaluations found participating systems were in practice increasing emissions rather than reducing them. Following 2019 program revisions–adding requirements for time-of-use enrollment and minimum battery-cycling thresholds–the program achieved net-negative emissions starting in 2020.[162] The lesson generalizes beyond SGIP: an operational requirement only assures the intended outcome if it is calibrated to actually produce that outcome, not merely to a proxy for it.

Equity Perspective

Bulk capacity cost reductions translate into ratepayer savings through avoided resource adequacy expenditures reflected in electricity rates. The distributional incidence parallels that of avoided energy costs: proportional rate reductions favor higher-consumption customers in absolute terms. An additional equity concern specific to capacity value is the demographic distribution of customers enrolled in grid services and VPP programs that realize this benefit: if VPP enrollment is concentrated among higher-income households, the incidental bill savings and program revenues from capacity value realization accrue disproportionately to those households while only the ratepayer benefit of avoided capacity costs is shared broadly. LMI enrollment requirements in procurement contracts, such as the 10% LMI sourcing requirement in the Sunrun-SCE VPP agreement, represent one approach to improving the distributional equity of capacity value realization.

Research note: Quantified estimates of the distributional incidence of bulk capacity cost savings across income groups in Washington are not available in the reviewed literature. This gap limits the precision of the equity assessment for this factor.

Avoided Distribution Capacity Costs

Avoided distribution capacity costs represent the reduction in local distribution infrastructure investment attributable to peak demand reduction by distributed resources at specific locations. Locational specificity is the defining feature: this benefit accrues only where resources are deployed at or near capacity-constrained feeders or substations, and the value varies dramatically across locations on the distribution system.

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[161] Utility Dive, "California program leverages storage to drive significant GHG reductions: Verdant Associates," reporting on analysis presented by Brian McAuley, Verdant Associates, Clean Energy States Alliance webinar, July 30, 2024, https://www.utilitydive.com/news/california-self-generation-incentive-program-sgip-energy-storage-ghg-emission-reductions/723499/

[162] California Public Utilities Commission Energy Division. (2024). *Self-Generation Incentive Program (SGIP) 2021–2022 Impact Evaluation*. Prepared by Verdant Associates. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2021-2022-impact-evaluation.pdf

Solar-Only Installations

Solar-only systems cannot be directed to discharge during local distribution peak periods and cannot self-select for location based on distribution capacity value under standard rate designs. Distribution capacity value from solar-only systems is essentially a coincidence between generation profile and local peak demand pattern.

Retail Rate Design / Grid Services Tariffs. Standard system-wide rates provide no locational signal directing solar installation to capacity-constrained feeders. Locational components of grid services tariffs, such as VDER's DRV and LSRV, can compensate solar installations at constrained locations for their contribution, but cannot direct solar generation during local peak periods not coincident with available irradiance.

Utility Procurements. Non-wires alternatives procurement programs can target specific capacity-constrained zones, but solar-only resources are rarely viable NWA candidates due to non-dispatchability. NWA programs have primarily targeted storage, demand response, and energy efficiency.

Deployment Incentives. Standard incentives provide no locational differentiation. Locationally differentiated incentive adders—higher levels in distribution-constrained zones—could direct solar deployment to high-value locations but require feeder-level planning data that most current programs do not incorporate.

Storage-Enabled Installations

Storage can be directed to discharge during local distribution peak periods regardless of solar generation conditions. The distribution capacity benefit is the factor most sensitive to locational targeting, making the mechanism's ability to direct deployment to constrained locations and dispatch to local peak periods especially important.

Retail Rate Design. System-wide TOU rates provide no locational differentiation. Storage responding to system-wide rate signals may incidentally provide distribution capacity relief if local and system peaks coincide, but this is not designed into the mechanism.

Grid Services Tariffs. Tariffs with explicit distribution capacity components—DRV and LSRV structures—can direct storage dispatch toward the specific hours and locations where distribution capacity value is highest, enabling near-full realization of this benefit at constrained locations.

Utility Procurements. NWA procurement programs offer the most demonstrated ability to realize distribution capacity value from storage. Con Edison's Brooklyn-Queens Demand Management program, which procured over 52 MW of distributed resources to defer a $1.2 billion substation upgrade, is the landmark U.S. example. Location-specific RFPs direct both deployment and operation toward the precise locations and operating conditions where distribution capacity value is maximized.

Deployment Incentives. Incentives realize distribution capacity value only to the extent that installed storage is subsequently dispatched by other mechanisms. Locationally differentiated

adders improve deployment targeting but do not substitute for an operational dispatch mechanism.

Equity Perspective

The equity dimension of distribution capacity costs comes down to an affordability question. How can the distribution grid be made more affordable, especially for disadvantaged households? Avoided distribution capacity costs benefit all ratepayers by deferring or avoiding grid upgrades whose costs would otherwise be recovered through rates. Whether distributed solar and storage reduces or increases energy bills for disadvantaged households depends on where they are distributed, and whether or not disadvantaged communities and households reap affordability benefits in terms of energy rates and energy bills, but also with respect to energy reliability and resilience and increased access to clean energy for transportation, heating, cooling, water heating, and cooking, and the resulting air quality and health benefits.

The distribution grid, especially in historically disadvantaged and underinvested communities, is where these constraints will be most difficult to overcome with traditional wires-based solutions. Research shows that disparities in grid infrastructure hosting capacity threaten to limit the ability to integrate solar power and electrified household appliances in many disadvantaged communities.[163] Solar + storage, along with grid upgrades will be necessary to increase access to clean, affordable, resilient energy in all communities. Mechanism design determines whether this happens. Statewide retail rates cannot direct deployment to specific feeders, but procurements and grid services tariffs with compensation at the local level, and deployment incentives that pay more in areas with strained grid capacity, can target disadvantaged communities, provided those communities are explicitly included in targeting criteria. Equity can also be incorporated in the metrics used in benefit-cost analysis.

Several metrics can measure these effects. Energy Cost Burden (ECB) and Energy Affordability Gap (EAG) are metrics that provide an equity lens on any energy cost impacts to households. ECB is the ratio of energy spending to income, and EAG is the sum of all energy costs above a certain accepted ECB. A ratio of greater than 6% of gross income has been used to indicate a household is highly burdened, thus costs above 6% would be counted in the EAG.[164] Gross income analysis, though, misses some of the affordability concerns, as areas and households with high housing, energy, transportation, taxes, food or medical costs will be more burdened than the average household.[165] The California Public Utilities Commission (CPUC) incorporates total utility spending, not just energy, and uses net income after housing and utilities in the denominator rather than gross income in their related Affordability Ratio.[166] California's Energy Commission (CEC) has developed an Energy Equity Indicators affordability tool which illustrates energy affordability

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[163] Brockway, A. M., Conde, J., & Callaway, D. (2021). Inequitable access to distributed energy resources due to grid infrastructure limits in California. Nature Energy, 6(9), Article 9. https://doi.org/10.1038/s41560-021-00887-6
[164] Colton, R. D. (2021). Ratepayer-Funded Utility Bill Affordability: A Path forward to Serve Low-Income Connecticut Residents. Fisher, Sheehan & Colton. https://www.michigan.gov/documents/mpsc/Connecticut_affordability_Final_040821_721903_7.pdf
[165] Murphy, P., & Kwoka, B. (2025). Outage Costs, Energy Resilience, and Equity. 2025 IEEE Conference on Technologies for Sustainability (SusTech), 1–8. https://doi.org/10.1109/SusTech63138.2025.11025723
[166] California Public Utilities Commission. (2019). Affordability Ratio. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability/affordability-ratio

through the lens of energy burden and energy affordability gap toward an integrated Energy Affordability Index.[167] These serve to identify opportunities to improve access to clean energy technologies for low-income customers and disadvantaged communities, increase clean energy investment in those communities, and improve community resilience to grid outages and extreme events.[168]

Small-scale systems offer another pathway. PSE Healthy Energy's National Energy Affordability Tool (NEAT)[169] and analysis from PSE Healthy Energy indicates that, for example, 500W balcony scale solar could save low-income rental households in the Bay Area of California $400-500 annually in energy bills. This analysis shows that the accessibility of balcony scale solar for renters (a renter can install without landlord assistance) and LMI households (lower cost, no connection fees). Because these plug-in systems primarily offset on-site consumption rather than exporting to the grid, they place little demand on distribution capacity. Policy that supports such systems can broaden access to distributed solar.

This is particularly important from the equity perspective, because when grid electricity prices increase or decrease energy bills for everyone, those who are already energy cost burdened will face the highest relative change in their energy bills. This is especially true in Washington because of the higher fraction of electricity in end use energy in homes (vs. gas or other in-home combustion).[170]

Distribution investments also shape reliability, because most customer outages originate on the distribution system. Retail customers that adopt solar + storage gain some resilience from the availability of on-site electricity during grid outages, and the value of avoided outages should be considered as part of the cost burden and equity metrics. Avoided outage costs (e.g. lost income, food spoilage, medicine spoilage) are normally considered private benefits, and so are often excluded from policy analysis. But often, especially for lower income households, outages can generate costs borne by public services outside of energy considerations, including food insecurity, emergency room visits caused by spoiled medicine, and more. Equity considerations in outage costs and mitigations are key for understanding the public and private costs of outages.[171] Research shows that Energy Affordability Gaps can increase significantly if outage costs are included as part of the energy cost; the value of distributed solar and storage toward resilience in disadvantaged communities is captured in this manner, where traditional outage cost analysis tends to emphasize outage costs in neighborhoods where incomes are higher, as outage costs are proxied by income.[172]

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[167] California Energy Commission. (2026). Energy Equity Indicators. California Energy Commission. https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/clean-energy-and-pollution-reduction-act-sb-350-3
[168] Ibid.
[169] Kinkhabwala, Y., et.al. (2026). National Energy Affordability Tool. Physicians, Scientists, and Engineers for Healthy Energy. https://energy-affordability-frontend.vercel.app/
[170] Burget, S. (2020). Elevating Equity: Strategies from State-Level Clean Energy Standards in the United States. Pitzer Senior Theses. https://scholarship.claremont.edu/pitzer_theses/112
[171] Murphy, P., & Kwoka, B. (2025). Outage Costs, Energy Resilience, and Equity. 2025 IEEE Conference on Technologies for Sustainability (SusTech), 1–8. https://doi.org/10.1109/SusTech63138.2025.11025723
[172] Ibid.

Research note: Washington-specific analysis of the geographic correlation between distribution system constraints and community income levels has not been conducted and would be needed to assess the distributional equity of distribution capacity policy with confidence.

Market Price Impacts

Market price impacts represent the reduction in wholesale market clearing prices from the supply-side effect of distributed generation on the price-setting margin. This reduction, known as the Demand Reduction Induced Price Effect (DRIPE), is a systemic consequence of deployment scale rather than a resource-level benefit realizable through individual mechanism design.

Across All Mechanism Types

No single policy mechanism directly realizes DRIPE; it is a portfolio-level co-benefit of aggregate deployment volume. Deployment incentives are the mechanism most directly connected to DRIPE realization because they most directly drive the installation volume on which the market price effect depends. Grid services tariffs that direct storage toward energy arbitrage may contribute to price smoothing at scale. Retail rate design affects DRIPE indirectly through its influence on adoption economics.

Equity Perspective

Market price impacts have a theoretically favorable equity profile. DRIPE benefits are socialized across all wholesale market buyers and flow to ratepayers regardless of whether they participate in distributed solar and storage programs. Unlike most other benefit factors, DRIPE does not require individual participation to receive the benefit, making it one of the few benefit categories whose distributional incidence is not contingent on who can access distributed energy programs. This socialized benefit structure makes DRIPE particularly important from an equity standpoint and provides a partial offset to the potential regressive cost shift associated with NEM export compensation.

Research note: The magnitude of DRIPE in Washington's specific wholesale market context is not well-documented. Washington's participation in the Western wholesale market and the dominant role of hydroelectric generation in setting marginal prices create conditions that differ significantly from the thermal-generation-dominated markets where most DRIPE analyses have been conducted. Washington-specific modeling is needed to assess whether DRIPE benefits are material at projected distributed resource penetration levels.

Increased Host Customer Resilience

Solar-only installations

Host customer resilience refers to the backup power capability that on-site storage provides during grid outages. Solar-only installations do not provide meaningful resilience in standard grid-tied configurations, so this analysis focuses specifically on storage-enabled installations.

An open question in this report is whether policy mechanisms–such as Net Energy Metering (NEM) rates and time-of-use rate design–should be credited with the resilience benefits of batteries, even when those benefits are never actively verified or realized.

One view holds that policy mechanisms deserve credit for both their intended and unintended effects, drawing an analogy to how greenhouse gas impacts are counted even though reducing them wasn't a deliberate goal of fossil fuel use. Favorable rate structures like NEM 2.0 substantially lower the cost of achieving resilience–shrinking what might otherwise be a multi-thousand-dollar investment down to a few hundred dollars–and this cost effect is real and causal, not merely theoretical. Prior research on community resilience hubs supports this view, suggesting that the shift from NEM 2.0 to NEM 3.0 already shaped real-world investment decisions for both households and resilience hubs.

A counterargument distinguishes between a mechanism that merely makes a benefit *possible* and one that *causes* the benefit to be realized. Installing a battery doesn't guarantee resilience value unless it's intentionally configured and used for that purpose–much as a grid-services program shouldn't get extra credit for outcomes it only made more affordable without ensuring they'd actually happen.

A battery can supply backup power during an outage only if it is installed with the equipment to do so, typically a transfer switch and an inverter able to operate independently of the grid. The majority of residential batteries are installed this way, so a residential battery paired with solar carries *some* resilience value by default. The same is not necessarily true of batteries at commercial buildings. The question for policy is not whether resilience value exists but how much of its *potential* is realized. Capturing the full value (for example through automatic islanding, load prioritization, or outage-triggered dispatch) typically depends on specific configuration choices, which are shaped by the rate design, incentives, and tariffs discussed elsewhere in this report. Resilience value thus scales with configuration rather than switching on or off. Accordingly, this report evaluates each mechanism by whether if encourages capture of the marginal resilience value, the difference between the baseline and maximized potential. For the residential solar plus storage systems that are the focus of this report, this baseline level of resilience is treated as a default assumption.

This report highlights this tension because it bears on broader cost-shift and policy-design questions relevant to Washington State. A useful resolving framework is that no single mechanism produces a benefit on its own: mechanisms create favorable conditions, and it's the combination of rate design, incentives, and tariffs together that drives deployment and the *degree* of benefit realization–not merely whether a benefit occurs. This logic already appears in the report's incentive-program section and could be extended elsewhere. At the same time, some benefits–such as distribution capacity value — depend on specific mechanisms (e.g., a grid services tariff) rather than the general presence of supportive policy; particular benefit types require particular unlocking mechanisms, whereas resilience appears to have a non-zero baseline that stacking mechanisms then amplify.

Finally, this report reflects this nuance by explaining that incentives "guide" outcomes but require interaction with other mechanisms to fully materialize. Policy structures allow for creative flexibility ("stacking") rather than implying outcomes are rigidly predetermined.[173]

Storage-Enabled Installations

Retail Rate Design. Rate design does not directly realize resilience benefits. The availability of backup power during an outage is a function of hardware configuration (island-mode inverter, automatic transfer switch) and the battery's state of charge at outage onset, neither of which is governed by the retail rate structure.

Grid Services Tariffs. A small number of jurisdictions have piloted “resilience as a service” programs that compensate storage for maintaining readiness for backup operation. Vermont’s Green Mountain Power’s Powerwall program, which provides subsidized battery installations in exchange for dispatch rights, with batteries providing backup power during outages, is the most developed example. Such programs are structurally promising but remain limited in scale.

Utility Procurements. Procurement contracts can incorporate resilience service obligations, but most current VPP programs target capacity or demand response as the primary service. Where procurement contracts explicitly require backup-capable hardware configuration and state-of-charge maintenance, the contracted fleet can provide both grid services and host customer resilience.

Deployment Incentives. Deployment incentives are the primary mechanism through which host customer resilience has been realized to date. Programs such as California's SGIP, with enhanced rebates for customers in high fire-threat districts and for medically vulnerable customers, directly subsidize the installation of backup-capable storage for customers with the greatest resilience needs. The key design condition is that incentive eligibility requires backup-capable hardware configuration, not merely storage installation.

Equity Perspective

Host customer resilience has among the clearest and most well-documented equity dimensions of any benefit factor in the representative set. LMI and medically vulnerable households face the highest resilience needs—outages are more likely to produce acute welfare and health impacts including spoiled medication, heat injuries, lost income, and food insecurity—while simultaneously facing the greatest structural barriers to storage adoption.[174] A deployment incentive program providing uniform per-kilowatt-hour rebates to all eligible customers will direct backup power capability primarily to households that can afford to participate, which tend to be higher-income. Tiered equity incentives, calibrated to overcome the larger capital access barriers and lower bill savings available to LMI households, are the most direct mechanism for aligning the distribution of resilience benefits with the distribution of resilience needs. Washington's existing

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[173] Murphy, et al. (2024). Modeling and design of solar + storage-powered community resilience hubs across California. *Risk Analysis*. https://onlinelibrary.wiley.com/doi/10.1111/risa.14341

[174] Murphy, P., & Kwoka, B. (2025). Outage Costs, Energy Resilience, and Equity. *2025 IEEE Conference on Technologies for Sustainability (SusTech)*, 1–8. https://doi.org/10.1109/SusTech63138.2025.11025723

enhanced incentives for income-eligible and home health customers in VPP programs represent a foundation that could be built upon and extended to a broader set of distributed storage programs.

Hydropower Ramping Reduction

Hydropower ramping reduction represents the operational and ecological benefits of reducing rapid output changes at Washington's hydroelectric facilities attributable to distributed storage dispatch. This is the most analytically novel factor in the representative set; no documented U.S. state regulatory proceeding has formally quantified it as part of a distributed energy resource cost-effectiveness analysis. In Appendix H we include a brief review of some of the research needs to better understand the implications of hydropower ramping.

Solar-Only Installations

Solar-only installations have an ambiguous and potentially adverse relationship with hydropower ramping. High solar penetration can intensify the duck curve, requiring steeper morning and evening ramps, rather than reducing ramping requirements. Solar-only installations are not treated as candidates for realizing this benefit.

Storage-Enabled Installations

Storage can reduce hydropower ramping by absorbing midday solar generation, reducing the need for hydro to ramp down, and by discharging during morning and evening ramp periods, reducing the need for hydro to ramp up steeply. Effective realization requires a policy mechanism that directs storage specifically toward ramping reduction, rather than toward energy arbitrage or peak capacity provision. No such mechanism currently exists in any U.S. jurisdiction, meaning this benefit represents a genuine policy innovation opportunity for Washington.

This benefit is also sensitive to sizing, not just to policy design. Ramping reduction depends on storage capacity being roughly matched to solar capacity, since the storage needs enough headroom to absorb the midday solar peak and enough discharge capability to cover the morning and evening ramps it's meant to smooth. If storage capacity is significantly undersized relative to solar capacity, it cannot meaningfully offset the ramp–the battery fills or empties too quickly to blunt the swing, and hydro still has to ramp steeply regardless. In that case, the benefit doesn't simply shrink; it can flip into a net cost, since the system incurs the capital and operational expense of storage without delivering the ramping reduction that would justify it. This means that, unlike some of the other benefits discussed in this report where a mechanism primarily governs *whether* value is captured, ramping reduction has a physical sizing precondition that policy alone cannot substitute for–a mechanism directing storage toward ramping reduction is necessary but not sufficient without capacity roughly commensurate with the solar it's meant to buffer.

Equity Perspective

Reducing hydropower ramping has equity implications that go beyond savings for ratepayers. Hydroelectric development on the Columbia and Snake rivers and their tributaries has imposed

costs on Tribal communities, including damage to salmon runs and to river ecosystems.[175] The rapid flow changes caused by ramping add to these harms: fluctuating flows can strand fish, displace them downstream, and disrupt spawning and rearing.[176] The Northwest Power and Conservation Council has proposed reducing ramping and daily flow fluctuations as part of its draft Columbia River Basin Fish and Wildlife Program.[177] Distributed storage that takes on some of the balancing work now performed by hydropower can therefore contribute, at the margin, to steadier river flows. Capturing this benefit also has particular significance for Tribal nations, which makes their involvement in the program design important.[178]

Research note: This area has the greatest evidentiary thinness in the equity analysis. No documented policy proceedings or academic studies were identified that have specifically examined the distributional benefits to Tribal communities from distributed solar and storage deployment through the hydropower ramping reduction pathway. This represents a significant gap that warrants dedicated research and meaningful Tribal consultation.

Improved Economic Wellbeing (Distributional Impacts)

Improved economic wellbeing—operationalized as reduction in household energy burden (ECB)—is the benefit factor most directly and explicitly concerned with equity outcomes. A household with an ECB above 6% of gross income is classified as highly energy burdened; energy burden at this level is associated with documented adverse health and financial outcomes.

Across All Installation Types

The distinction between solar-only and storage-enabled installations is less analytically decisive for this factor than for generation- and capacity-tier factors. What matters most is whether the program design reaches LMI households, renters, multifamily residents, and other groups facing structural access barriers.

Retail Rate Design. Standard retail rate design does not specifically target distributional impacts. Rate structures that increase fixed charges to limit cost shifts may worsen energy burdens for low-consumption LMI customers, as a fixed charge tends to be a larger portion of the bill and of the household income for LMI households. Income-differentiated export compensation, such as PacifiCorp's equitable access credit in Washington's first NEM successor tariff, represents a direct mechanism for improving the distributional equity of rate design.

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[175] Hester et Al. (2026). River Restoration in the Context of Hydropower Impacts to Anadromous Fish in Large River Networks: Evidence from the Columbia River Basin With Implications for Future Research. *River Research and Applications.* https://onlinelibrary.wiley.com/doi/10.1002/rra.70111

[176] Young, P.S., Cech, J.J., & Thompson, L.C. (2011). Hydropower-related pulsed-flow impacts on stream fishes: A brief review, conceptual model, knowledge gaps, and research needs. *Reviews in Fish Biology and Fisheries,* 21, 713-731. https://doi.org/10.1007/s11160-011-9211-0

[177] Northwest Power and Conservation Council. (2025, December 23). Council approves draft Columbia Fish and Wildlife Program for public review and comment.

[178] Native American Rights Fund. (2026, January 26). *Tribal Engagement in FERC Hydropower Licensing*. https://narf.org/headwaters-ferc/

Grid Services Tariffs. Grid services tariffs improve the economics of solar and storage adoption for participants but do not themselves address structural access barriers. VPP aggregators that extend program access to LMI households, through community solar arrangements or targeted outreach, can improve distributional equity, but only if explicitly designed to do so.

Utility Procurements. Standard VPP procurement programs do not incorporate income-based targeting. LMI enrollment requirements in procurement contracts, such as the 10% LMI sourcing requirement in the Sunrun-SCE agreement, can improve distributional equity but require an upstream supply of LMI-hosted distributed resources to be effective.

Deployment Incentives. Deployment incentives are the mechanism most capable of realizing improved economic wellbeing for LMI households through income-based eligibility tiers with enhanced incentive levels, multifamily program structures, on-bill financing,[179] and outreach and application assistance. The empirical evidence for the energy burden reduction potential of well-targeted solar incentive programs is substantial: a 2025 Nature Energy study found solar adoption reduces LMI households' probability of being unable to pay electricity bills by 44% and their probability of receiving disconnection notices by 46%.[180] Balcony-scale solar-plus-storage systems represent an emerging access pathway for renters and multifamily residents that merits explicit consideration in Washington program design, and notably sidesteps the financing risks below, since its low cost profile reduces or eliminates the need for financing in the first place.

Equity Perspective

Improved economic wellbeing is the benefit factor most intrinsically concerned with equity, and its equity analysis is inseparable from its effectiveness analysis. Washington's statutory obligation to pursue equitable distribution of clean energy benefits and reduction of burdens for vulnerable populations requires that distributed solar and storage policy be designed to extend the energy burden reduction benefits of solar adoption to LMI households as a primary objective rather than a secondary aspiration. The historical pattern of solar adoption, concentrated in higher-income, owner-occupied, single-family households, represents a baseline failure of distributional equity that active policy design must counteract. Programs modeled on California's Solar on Multifamily Affordable Housing (SOMAH) initiative, SGIP equity budgets with adequate funding so as to not be chronically undersubscribed by LMI households, and community solar frameworks with LMI carve-outs provide transferable design models that Washington should evaluate for adaptation to the state's specific regulatory and demographic context.[181, 182, 183] As noted above, finance mechanisms must include protections that ensure LMI households do not face increased risk of

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[179] On-bill financing can address access issues, but also lacks some of the protections traditional loans are required to offer, can expose LMI households to non-payment penalties, and block access to zero-cost programs. See Haynes, B. (n.d.). *Tariffed On-Bill Financing Poses Significant Risks for Low-Income Consumers. NCLC*. https://www.nclc.org/resources/tariffed-on-bill-financing-poses-significant-risks-for-low-income-consumers/

[180] Yozwiak, M., et al. (2025). *The effect of residential solar on energy insecurity among low- to moderate-income households.* Nature Energy, 10(5), 569–580. https://doi.org/10.1038/s41560-025-01730-y

[181] SOMAH | *Solar on Multifamily Affordable Housing*. (n.d.). https://calsomah.org/

[182] California Public Utilities Commission. *Self-Generation Incentive Program*. (n.d.). https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program

[183] Burget, S. (2020). *Elevating Equity: Strategies from State-Level Clean Energy Standards in the United States. Pitzer Senior Theses*. https://scholarship.claremont.edu/pitzer_theses/112

predatory loans due to lack of capital and access to traditional finance, else they risk further financial hardship and power shut-offs due to inability to repay on-bill finance loans.[184]

Job Creation and Economic Development

Job creation and economic development benefits are primarily a function of deployment volume and the local content of installation activity, rather than of how deployed resources operate. There is a fundamental difference in job creation between grid-scale deployment and distributed roof-top deployment, especially residential roof-top deployment. Larger scale deployments tend to include labor agreements and workforce development requirements. While smaller distributed systems can create more jobs per MW deployed, they have tended to have less impact on long-term, quality job creation.

Across All Mechanisms

Deployment incentives are the mechanism most directly connected to job creation through their effect on installation volume. Retail rate design, grid services tariffs, and utility procurements affect job creation indirectly through their influence on deployment economics and long-term revenue certainty for installers and aggregators. None of these mechanisms directly targets job creation as an objective or incorporates workforce requirements as design features in current practice.

Equity Perspective

The equity dimensions of job creation benefits depend on the geographic and demographic distribution of installation activity. Solar installation is a place-based activity whose employment benefits accrue primarily to workers and businesses serving the neighborhoods where installations occur. Historically solar deployment concentrated in higher-income areas has directed employment benefits toward workers serving those areas. Workforce equity provisions in incentive program design—local hire requirements, workforce diversity targets, training program participation requirements—can improve the distributional equity of job creation benefits and ensure that the economic development value of distributed solar and storage deployment reaches workers in historically underserved, LMI, and environmental justice communities.[185, 186]

Research note: The available peer reviewed rooftop solar workforce equity literature is primarily focused on California and Europe and may not transfer directly to Washington's labor market.

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[184] Haynes, B. (n.d.). *Tariffed On-Bill Financing Poses Significant Risks for Low-Income Consumers*. NCLC. https://www.nclc.org/resources/tariffed-on-bill-financing-poses-significant-risks-for-low-income-consumers/
[185] Gadzanku et al. (April 2023) *An Updated Review of the Solar PV Installation Workforce Literature*. NREL/TP-7A40-83652, National Renewable Energy Laboratory. https://www.osti.gov/servlets/purl/1971876
[186] The Solar Foundation. (2019). *Oregon and Washington solar workforce diversity report*. https://nwenergy.org/wp-content/uploads/2019/07/ORWA-Diversity.pdf

Washington-specific workforce equity analysis, considering DER impacts on local workforce, would strengthen this assessment.[187, 188]

Summary: Benefit Realization and Equity Profile by Factor and Mechanism

Table 5 consolidates the benefit realization characterizations and equity profiles. For mechanism effectiveness, the scale is: High / Moderate / Low / N/A. For equity profile, the scale reflects the distributional favorability of the benefit as typically realized under current mechanism designs: Favorable (benefit tends to reach LMI and vulnerable populations equitably or better); Mixed (benefit has both favorable and unfavorable distributional dimensions, depending on design); Unfavorable (benefit tends to concentrate in higher-income populations under typical designs); and Design-Dependent (distributional incidence is highly sensitive to specific mechanism design choices).

Table 5. Benefit Realization and Equity Profile Summary

RRD = Retail Rate Design	PRO = Procurement
GST = Grid Services Tariff	INC = Incentive

Benefit Factor	RRD Solar	RRD Storage	GST Solar	GST Storage	PRO Solar	PRO Storage	INC Both	Equity Profile
Avoided Energy Costs	Mod	High	Mod	Mod	N/A	Low	Low*	Mixed
Avoided Bulk Capacity	Low	Mod	Mod	High	N/A	High	Low*	Design-Dep.
Avoided Distribution Capacity	Low	Low	Mod	High	N/A	High	Low*	Design-Dep.
Market Price Impacts	Low	Low	Low	Low	Low	Low	Mod	Favorable
Host Customer Resilience	N/A	Low	N/A	Mod	N/A	Mod	High*	Unfavorable *

[187] Fabra, N. et al. (2024). *Do renewable energy investments create local jobs?* Journal of Public Economics, 239, 105212. https://doi.org/10.1016/j.jpubeco.2024.105212

[188] Tourkolias, C., & Mirasgedis, S. (2011). *Quantification and monetization of employment benefits associated with renewable energy technologies in Greece*. Renewable and Sustainable Energy Reviews, 15(6), 2876–2886. https://www.sciencedirect.com/science/article/abs/pii/S136403211100075X?via%3Dihub

Benefit Factor	RRD Solar	RRD Storage	GST Solar	GST Storage	PRO Solar	PRO Storage	INC Both	Equity Profile
Hydropower Ramping	N/A	Low	N/A	Mod*	N/A	Mod*	N/A	Thin evidence
Improved Economic Wellbeing	Low	Low	Low	Low	Low	Low	High*	Design-Dep.
Job Creation / Econ. Dev.	Low	Low	Low	Low	Low	Low	Mod	Design-Dep.

Equity profile reflects typical design conditions; targeted design provisions can shift the profile significantly.

Unfavorable = unfavorable under generic design but can be made Design-Dependent or Favorable with explicit equity provisions.*

Findings on Benefit Realization by Mechanism

The benefit realization analysis produced findings at two levels: factor-specific findings about how each benefit factor is realized under each mechanism, and cross-cutting findings about the structural relationships between mechanism design and benefit realization that hold across multiple factors.

Storage Attachment Is the Single Most Consequential Variable for Benefit Realization

Across every benefit factor in the representative set, storage-enabled installations realize higher or equal benefit levels compared to solar-only installations, and in several factors the difference is categorical rather than marginal. Solar-only installations realize little or no bulk capacity value, little or no distribution capacity value, and no host customer resilience benefit regardless of which mechanism governs them. Storage-enabled installations can realize substantial benefits in all three categories under appropriate mechanism designs. For avoided energy costs, storage's ability to perform temporal arbitrage substantially increases realized benefit relative to the passive coincidence available to solar-only systems.

The policy implication is unambiguous: mechanism design should, to the greatest extent possible, be structured to promote the attachment of storage to solar installations. This means not merely allowing paired storage to qualify for the same compensation as solar-only systems, but actively creating economic incentives that make storage attachment financially attractive—through TOU rate differentials that reward temporal arbitrage, grid services compensation that is available to storage-enabled but not solar-only resources, and incentive programs that provide enhanced rebates for storage paired with solar. As solar penetration increases and the marginal value of solar-only generation declines, the case for storage attachment grows stronger over time.

No Single Mechanism Realizes All Benefit Factors Effectively

The analysis confirms that no single policy mechanism is sufficient to realize the full array of potential distributed solar and storage benefits. The mechanisms are structurally complementary, each best suited to realizing a distinct subset of benefit factors:

- Retail rate design is most effective at realizing avoided energy costs from storage-enabled installations through temporal arbitrage incentives, but provides limited ability to capture distribution-tier value or to direct deployment toward LMI households.
- Grid services tariffs are most effective at realizing bulk and distribution capacity costs from storage-enabled installations, particularly where tariff design includes explicit capacity value components and locational differentiation, but do not address host customer resilience or distributional economic impacts without explicit design features.
- Utility procurements are most effective at realizing both bulk and distribution capacity costs from storage-enabled installations where capacity provision is specified as the primary contracted service, and offer the greatest potential for net positive ratepayer value as the market matures, but are slow, transaction-intensive, and poorly suited as the primary driver of broad-based distributed resource deployment.
- Deployment incentives are most effective at realizing host customer resilience and improved economic wellbeing for targeted populations, and are the mechanism most directly capable of driving the deployment volume on which market price impacts (DRIPE) depend, but do not by themselves ensure that deployed assets operate in ways that realize energy or capacity benefits.

This complementarity is not a design failure; it reflects the genuine diversity of the value streams that distributed solar and storage can provide, each of which has different temporal, locational, and behavioral characteristics that call for different policy instruments. The appropriate policy response is not to choose among the mechanisms but to design a portfolio that combines them in ways that maximize aggregate benefit realization at minimum aggregate cost.

Mechanism Design Quality Matters as Much as Mechanism Choice

The benefit realization analysis reveals that the quality of mechanism design—the precision with which price signals, dispatch protocols, compensation structures, and eligibility conditions are calibrated to the actual value of the targeted benefits—is as consequential as the choice of which mechanism type to employ. A well-designed retail rate structure with accurate TOU differentiation and value-reflective export compensation realizes substantially more avoided energy cost benefit than a poorly designed rate structure with flat rates and full-retail-rate NEM compensation. A grid services tariff with precise dispatch protocols and capacity value components aligned with actual system peak periods realizes substantially more bulk capacity benefit than a generic demand response program with static event windows. The policy design task is not simply to select a mechanism type but to design it well.

Several mechanism design features emerged from the analysis as particularly consequential for benefit realization:

- Time differentiation of both import rates and export compensation, aligned with actual wholesale cost patterns, is the foundational design requirement for realizing avoided energy costs from storage-enabled installations.
- Explicit capacity value components in grid services tariffs (compensating storage specifically for discharge during capacity-critical periods) are necessary to realize bulk capacity benefits beyond what retail rate TOU differentials can achieve.
- Locational differentiation in grid services tariffs and deployment incentives is necessary to realize distribution capacity benefits, which are inherently location-specific and cannot be captured through system-wide rate signals. However, locational differentiation is worth flagging as a real tension, because once it is established as legitimate, that precedent can be extended beyond its original purpose, inviting disputes over how boundaries are drawn, added administrative complexity, and pressure to use locational signals for reasons unrelated to distribution capacity. At the same time, the underlying problem is genuine: a system-wide rate signal structurally cannot reflect location-specific grid value. Locational differentiation should be treated as a narrowly scoped tool for distribution capacity specifically, with clear, objective, auditable criteria, rather than a general principle to extend by default elsewhere.
- Operational requirements in deployment incentive programs—conditioning incentive eligibility on enrollment in qualifying grid services programs or maintaining backup-capable hardware configurations—are necessary to ensure that incentivized deployments realize the operational benefits the incentive was designed to enable.

Hydropower Ramping Reduction Requires New Mechanism Design

No currently implemented U.S. policy mechanism has been specifically designed to realize this benefit. This report suggests a methodological framework for quantifying it, and identifies the general mechanism design features that would be required to realize it–a grid services tariff or procurement program that compensates storage specifically for dispatch during hydropower ramping periods.

Washington is the jurisdiction well positioned to develop and pilot such a mechanism, given the centrality of hydroelectric generation to the state's electricity system. Realizing this benefit, however, would be a substantial implementation undertaking. Hydropower ramping in the Pacific Northwest is governed by a complex, multi-party operational framework–most notably involving the Bonneville Power Administration (BPA)--that balances electricity generation against flood control, navigation, irrigation, and other mandates. Any mechanism directing storage dispatch toward ramping reduction would need close, sustained collaboration with BPA and other dam operators to align with existing hydro operations rather than work against them. It would also need to navigate significant ecological considerations, since hydropower ramping schedules are themselves shaped by constraints tied to fish passage, river flow requirements, and other environmental protections, meaning any change to ramping patterns carries downstream ecological implications that would require careful evaluation alongside the energy benefits. A brief discussion of these issues is found in Appendix H. The development of this mechanism design nonetheless represents a genuine policy innovation opportunity for Washington that no other state has yet pursued.

Market Price Impacts Are a Portfolio-Level Co-Benefit, Not a Mechanism-Level Target

Market price impacts (DRIPE) stand apart from the other benefit factors in the representative set because they are a systemic consequence of aggregate deployment volume rather than a resource-level benefit that any individual mechanism can target or realize. The mechanism implication is that DRIPE should be incorporated as a portfolio-level co-benefit in Washington's distributed energy resource cost-effectiveness analysis, calculated as an aggregate effect of the total deployed fleet across all mechanisms, rather than as a factor that individual mechanism designs should attempt to optimize. The mechanisms that most affect the magnitude of DRIPE realized are those that most effectively drive deployment volume, primarily deployment incentives and favorable retail rate design.

IX. CHARACTERIZATION OF POLICY MECHANISMS BY COSTS

Understanding the cost-effectiveness of policy mechanisms requires examining the costs each mechanism incurs in delivering benefits. Importantly, mechanisms are not selected in isolation based solely on cost-effectiveness. Because deployment of behind-the-meter solar and storage results from a combination of mechanisms (e.g., favorable rate design and incentive programs), cost-effectiveness is best evaluated at the portfolio level.

As described previously, there are two types of costs:

- **Mechanism costs**: The costs of the mechanism itself, which are used to subsidize deployment, compensate asset developers, and/or provide savings to customers that install the assets.
- **Other cost factors**: Deploying distributed solar and storage can also increase certain system costs. The size of these increases depends both on how many resources are deployed and where, and on the rules that govern how the resources operate. This report considered two such cost factors: increased bulk capacity costs and increased distribution capacity costs. Both can be generally quantified. Their magnitude varies widely. At low levels of deployment, or where the policy mechanism coordinates when and how storage charges and discharges, they are typically small relative to mechanism costs. At higher levels of deployment, or under mechanisms that exert little control over operation, they can be significant.

Characterizing costs by mechanism

To compare the cost-effectiveness of different policy mechanisms, there must be a common metric that is linked to how the realization of benefits is measured. For solar, this metric is $/kW of solar deployed; for storage, this metric is typically $/kWh of storage capacity deployed. Note that in both cases, these metrics do not reflect the installation cost of the hardware; rather, these metrics are the expenditures related to the policy mechanism that facilitates the deployment of the assets. The costs of the policy mechanism(s) are borne by ratepayers, taxpayers, or both.

Retail Rate Design

As described in Section V, the cost of rate design mechanisms is the cost shift of electric system infrastructure and supply costs from customers who reduce their grid consumption through solar self-generation or storage dispatch to customers who do not. It may arise because the fixed costs of the electricity system must be recovered from a shrinking base of volumetric consumption as self-generation reduces participating customers' grid purchases.

Under traditional full-retail-rate NEM, the cost shift is maximized: customers receive credit for exported energy at the full retail rate, which bundles generation, transmission, distribution, and fixed cost recovery into a single volumetric price. The utility's costs are reduced only by its actual avoided supply cost—typically substantially lower than the retail rate—and the difference is recovered from non-participating ratepayers.

Reducing the export compensation rate toward avoided cost directly reduces the cost shift. California's NEM 3.0 represents the most aggressive application of this lever. Value-of-solar tariffs, avoided-cost-based compensation with time differentiation, and net billing structures that separate on-site consumption from exported generation all represent calibration approaches implemented in various jurisdictions. Storage-enabled installations interact differently: a system charging and discharging on-site without exporting may produce minimal cost shift through export compensation but may reduce contributions to on-peak cost recovery through load shifting, creating an analogous though typically smaller cost allocation effect under flat retail rates.

Fixed charge design is also relevant: rate structures recovering a greater share of fixed costs through customer charges reduce the per-kilowatt-hour cost shift but impose fixed financial obligations on low-consumption customers that carry their own distributional equity concerns.

Mechanism Choices Based on Cost Shift

When specialized rate design such as NEM was the only or primary mechanism to deploy solar, the policy decisions were focused on reducing the potential for cost shift as much as possible while still making it economically viable for customers. However, if taking an approach where a portfolio of mechanisms work together to deploy solar (and storage), rates may be designed to drive the potential cost shift to zero, while the other mechanisms fill any remaining gaps, as discussed elsewhere in this report.

Going forward, rates and export compensation can be based on the actual value customers provide to the grid rather than on special incentives for solar or storage. This approach minimizes or eliminates cost shifting between customers. Any additional support for solar or storage deployment can be provided through separate programs rather than through electricity rates.

Equity Perspective

The distributional equity related to the NEM cost shift is the most contested empirical question in distributed solar policy, and it is particularly consequential in Washington given the state's higher reliance on electricity than many states for its overall energy use. The theoretical incidence is regressive: solar adopters (predominantly higher-income owner-occupied households) reduce bills through self-generation while the utility’s revenue shortfall is recovered from all ratepayers, including lower-income households who cannot access solar.

The observed size of the cost shift remains uncertain: analysts who incorporate the full range of system benefits provided by NEM participants–avoided peak capacity costs, reduced transmission congestion, and other services not captured in standard avoided cost methodologies–conclude that the net cost shift may be substantially smaller than conventional analyses suggest, or even negative. More empirical research that analyzes the full range of benefits is needed.

Washington's NEM successor regulatory proceedings should be designed to accommodate comprehensive benefit valuation rather than relying on narrowly defined avoided cost analysis. Whatever the magnitude, Washington's high use of electricity amplifies the energy burden consequences of rate increases attributable to cost shifts, making the equitable mitigation of cost shift of significant importance relative to most peer states. The most durable approach combines

export compensation reform that limits cost shifts at the source with LMI incentive programs that increase solar access for lower-income households, addressing both the distributional cost concern and the distributional access concern simultaneously.

Other Cost Factors: System Costs

Increased system costs represent the incremental costs imposed on the electricity system by distributed resource deployment and operation. This report identified two of these costs for further study: bulk system capacity costs and distribution infrastructure capacity costs.

Bulk Capacity Costs

Solar Only

At low penetration, distributed solar variability is absorbed within normal operating reserves without material cost increases. At higher penetration, the steep net load ramp that occurs as solar generation declines in the late afternoon–the duck curve–can require additional flexible capacity, increased reserve requirements, and more frequent peaking resource dispatch.[189]

In Washington's hydroelectric-dominated system, hydro flexibility has historically provided a substantial buffer, but the marginal cost of accommodating additional solar variability through hydro dispatch will increase as penetration grows and as environmental flow constraints and water management obligations limit operational flexibility.

As with the Bulk Capacity Benefits, for solar-only installations, the choice and design of mechanisms does not make a significant difference in this cost factor. Because the solar-only installation is not dispatchable, the increased bulk capacity costs will depend on the installation of the hardware and resulting generation profile and not the mechanisms themselves.

Storage-enabled installations

Storage installations can mitigate bulk system operational costs by smoothing net load variability, but only when dispatched in alignment with system flexibility needs, a function of mechanism design rather than hardware capability.

Thus with storage, the choice and design of the mechanisms makes a significant difference in the increased Bulk Capacity Costs caused by these deployments. Each of the mechanisms can be designed to minimize additional costs. In fact, as was described above, if the mechanism is specifically targeting Bulk Capacity Benefits, then this cost factor would be zero.

[189] California Independent System Operator (CAISO), *What the Duck Curve Tells Us About Managing a Green Grid*, Fast Facts, 2016, https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf

Distribution Capacity Costs

Solar Only

High solar penetration can cause under-voltage and over-voltage excursions, accelerated transformer thermal cycling, and reverse power flow impacts on distribution equipment not designed for bidirectional energy flows.

Retail Rate Design. For solar-only installations, locationally differentiated export compensation could reduce system cost impacts by directing deployment away from constrained feeders, but requires feeder-level distribution planning data that utility distribution systems are only beginning to produce systematically.

Grid Services Tariffs. For solar-only installations, locational tariff components can redirect deployment away from the most constrained feeders.

Utility Procurements. N/A for solar-only

Deployment Incentives. Locational incentive differentiation can reduce deployment-related system costs by directing installation to areas with ample hosting capacity.

Storage-enabled installations

Retail Rate Design. Storage charging creates demand that may produce coincident distribution peaks if many systems respond to the same rate signal simultaneously, a rebound effect that can offset some of the distribution capacity benefits of storage dispatch. The net distribution system cost impact of storage deployment depends on whether rate design differentiates by time and location precisely enough to avoid synchronized customer response — without that differentiation, storage can increase rather than decrease distribution capacity costs.

Grid Services Tariffs. Grid services programs with specified dispatch protocols and charging windows can substantially reduce distribution system cost impacts of storage by directing discharge toward peak demand periods and limiting charging to off-peak windows that avoid coincident loading.

Utility Procurements. Procurement contracts can specify precise operating parameters, including charging constraints, that minimize net distribution system costs while maximizing distribution capacity benefit. This level of operational specificity is not achievable under retail rate design or standard grid services tariffs.

Deployment Incentives. Incentive programs have the least control over system costs because they generally do not include dispatch requirements. Incentivized storage often charges at the same time, for example when off-peak rates begin, which can create new peaks on constrained circuits. Requiring incentivized systems to enroll in grid services programs with dispatch protocols is the main way to limit this risk.

Equity Perspective

Increased system costs are recovered through electricity rates and therefore affect household energy burdens in the same manner as cost shifts. Washington's high electric end-use share amplifies the equity significance of system cost-related rate increases for LMI households. An additional equity dimension specific to distribution system costs is the geographic pattern of distributed resource deployment relative to distribution system constraints: if constrained feeders are located in lower-income or historically underserved communities where load growth has outpaced infrastructure investment, the system cost increases attributable to distributed resource deployment in those communities impose a localized burden on lower-income ratepayers without necessarily producing proportionate local benefits.

Rate impact mitigation programs for LMI customers can partially offset energy burden increases from system cost-related rate adjustments, but a more durable approach limits system cost increases at the source through mechanism designs that incorporate dispatch requirements and locational differentiation. The coordination of incentive programs with grid services programs is particularly important from an equity standpoint: a storage system deployed in an LMI community under an equity-targeted incentive program but operated without grid services dispatch alignment may increase local distribution system costs while providing the host customer with resilience and bill savings benefits, producing a net equity outcome that depends on the relative magnitude of these effects.

Summary: Cost Factor Incidence, Mechanism, and Equity Profile

Table 6. Cost Factor Incidence by Mechanism and Equity Profile

RRD = Retail Rate Design GST = Grid Services Tariff	PRO = Procurement INC = Incentive

Cost Factor	RRD Solar	RRD Storage	GST Solar	GST Storage	PRO Solar	PRO Storage	INC (Both)
Cost level ratings: High = significant costs without design countermeasures | Mod = meaningful but designable | Low = limited under appropriate design | Minimal = negligible or offset by direct benefit							
Bulk System Operational Costs	Mod–High	Low–Mod	Mod	Low	N/A	Minimal	Mod–High*
Distribution System Costs	Mod	Mod*	Low–Mod	Low*	N/A	Minimal*	Mod–High*

Equity note: *All cost factors impose costs recovered through electricity rates and therefore affect household energy burdens. Washington's high electric end-use share amplifies the equity significance of rate increases for LMI households across all cost categories. Cost shift under retail rate design is the dominant equity concern and is amplified by the historical demographic concentration of solar adoption in higher-income households.*

Cross-Cutting Observations

Four observations from the integrated efficiency-and-equity cost factor analysis are consequential for Washington's policy design process.

1) The cost shift is the dominant cost concern and is overwhelmingly concentrated in the retail rate design mechanism. Its equity significance in Washington is amplified beyond most states by the high electric end-use share, making cost shift mitigation an equity imperative as well as an efficiency objective. The analytical task for Washington regulatory proceedings is not merely to measure the cost shift under alternative rate designs but to evaluate it in the context of the full range of system benefits that participating customers provide—benefits that comprehensive valuation may reveal to be larger than the cost shift itself.

2) Storage-enabled installations are associated with substantially lower net system costs than solar-only installations under virtually every mechanism, but only under mechanism designs that include appropriate operational constraints. The system cost risk of storage deployment is a function of mechanism design, not of the technology itself.

3) The cost shift and increased system costs interact through the rate design mechanism: rate adjustments designed to recover cost shift-related revenue shortfalls increase electricity prices for all customers, amplifying energy burden impacts on LMI households. Understanding these interactions requires integrated analysis of cost shift magnitude, system cost impacts, and distributional incidence—analysis that cannot be conducted within any single cost factor or benefit-cost test framework.

4) Washington's statutory equity obligations require that cost factor analysis be conducted with explicit attention to the distributional incidence of costs across income groups, not merely as an add-on to aggregate cost-effectiveness analysis but as a co-equal analytical requirement. This is true across policy mechanisms. Rate design proceedings in particular should be structured to produce this integrated analysis as a standard deliverable, not as an optional supplement.

Findings on Cost Incidence by Mechanism

The cost factor analysis produced findings that are analytically important for policy design and that carry significant equity implications in Washington's specific context.

The Cost Shift Is the Dominant Cost Concern and Is Concentrated in Retail Rate Design

Of the cost factors analyzed, the cost shift to non-participating ratepayers is the most significant in magnitude, the most directly policy-controllable, and the most contested analytically. The potential for cost shift is concentrated in the retail rate design mechanism: under traditional full-retail-rate NEM, any difference between the bundled retail rate export credit and the utility's actual avoided supply cost constitutes a systematic transfer from non-participating ratepayers to participating customers. The magnitude of this transfer varies substantially across jurisdictions and analytical methodologies, ranging from zero to approximately $0.08 per kilowatt-hour of exports in documented state proceedings.

A critical finding from this research is that the magnitude of the cost shift depends fundamentally on what system benefits are included in the benefit-cost analysis. Analyses that incorporate the full range of system benefits that NEM participants provide, including peak capacity contributions, transmission congestion relief, and environmental benefits not captured in standard avoided cost methodologies, produce substantially smaller cost shift estimates than analyses that rely on narrow avoided cost metrics. Washington's NEM successor regulatory proceedings would benefit from a design that accommodates comprehensive benefit valuation. Proceedings that use narrow avoided cost methodologies risk overstating the cost shift and thereby producing export compensation structures that are more restrictive than the underlying economics justify.

Increased System Costs Are Manageable for Storage-Enabled Installations Under Appropriate Mechanism Design

The analysis of increased bulk and distribution system costs reveals that storage-enabled installations are associated with substantially lower net system cost impacts than solar-only installations under virtually every mechanism—but only under mechanism designs that include appropriate operational constraints. A storage system deployed without dispatch requirements or TOU rate incentives may charge during off-peak periods that create co-incident distribution loading peaks, increasing system costs without providing the peak-shaving dispatch that would reduce them. The same storage system deployed under a well-designed combination of TOU rates and grid services program enrollment, with charging windows specified to avoid co-incident peaks and discharge obligations aligned with local distribution peak periods, can minimize net system cost impacts while maximizing distribution capacity benefit realization.

This finding has a direct policy implication: the system cost risks of storage-enabled distributed resource deployment are a function of mechanism design choices rather than of the technology itself. The decision to deploy storage at scale without accompanying mechanism design for operational alignment is a policy choice that will produce avoidable system cost increases. Conversely, the combination of good retail rate design, targeted grid services programs, and coordinated incentive program design can substantially limit system cost increases while maximizing benefit realization.

The Cost Shift and Increased System Costs Interact Through Rate Design

The cost shift and increased system costs are not independent phenomena; they interact through the retail rate design mechanism in ways that complicate their separate analysis and that have important equity implications. **Rate adjustments designed to recover utility revenues lost to NEM cost shifts—the rate increases that follow when cost shifts are not addressed through export compensation reform—increase electricity prices for all customers, including LMI households with limited ability to absorb rate increases.** Rate structures designed to limit cost shifts by recovering more fixed costs through customer charges may reduce the volumetric cost shift while imposing fixed financial burdens on low-consumption customers that are regressive in a different sense.

Understanding these interactions requires an integrated analysis of cost shift magnitude, system cost impacts, and distributional incidence—an analysis that cannot be conducted within the framework of any single cost factor or any single benefit-cost test. Washington's regulatory proceedings for NEM successor tariffs should be structured to require this integrated analysis as a standard deliverable.

Deployment Incentive Cost Shifts Are Potentially Regressive in the Absence of LMI Targeting

Ratepayer-funded deployment incentive programs generate cost shifts through direct transfer: a per-kilowatt-hour surcharge on all customers funds installation subsidies to participating customers who install solar and storage. Where participants are disproportionately higher-income—as has historically been the case for solar incentive programs without deliberate equity-focused design—the program constitutes a regressive transfer from lower-income ratepayers to higher-income program participants. **Well-calibrated incentive levels set at the minimum required for economic deployment, declining block structures that reduce incentives as technology costs fall, and LMI-targeted provisions that direct enhanced incentives to lower-income participants are the primary design tools for limiting the regressive transfer risk of deployment incentive programs.** In addition, deployment incentives funded from non-ratepayer mechanisms (e.g. taxes) can avoid regressive cost shifts, and may be more appropriate when the benefits of such programs extend beyond the energy system.

X. SUMMARY OF RESEARCH RESULTS

This section consolidates the report's principal findings, organized to trace the analytical arc of the project from its methodological foundations through its substantive conclusions. The findings are presented in six parts: the evolution of the project's research question and scope; findings from the factor selection process; findings on benefit realization by mechanism; findings on cost incidence by mechanism; cross-cutting findings on mechanism design and portfolio considerations; and findings on the state of the evidence base and directions for further research. Table 7 consolidates the findings.

A framing observation applies throughout: this project did not produce a definitive quantitative answer to the question of which policy mechanisms Washington should implement, or at what compensation levels, to maximize the realized benefits of distributed solar and storage. Instead, the research produced an analytical methodological framework, a structured evidence base, and a set of design principles that together equip Washington policymakers to answer questions through the legislative processes and regulatory proceedings in which the specific policy choices will ultimately be made. The value of this report lies not in conclusions about specific dollar figures -- which require Washington-specific data and modeling that exceed the scope and resources of this project -- but in its demonstration of the analytical approaches through which those figures can be credibly produced and evaluated.

Evolution of the Research Question and Project Scope

The most consequential finding to emerge from these efforts is structural. The project's primary research question evolved materially between the project's first and second years (Phase 1 and Phase 2), and that evolution has fundamental implications for how Washington's distributed solar and storage policy could be designed and evaluated.

Phase 1 was understood by many stakeholders as primarily addressing the rate design question of how exported solar generation could be compensated following the expiration or limitation of traditional net energy metering. This framing treated NEM successor tariff design as the central policy instrument and treated the value of distributed solar and storage as a question answerable through a utility-specific avoided cost study of the kind that other states have conducted in their own NEM proceedings.

Phase 2 research, authorized by the second budget proviso (see Section I) created the opportunity to examine other policy mechanisms to support the policy goals Washington has established. The principal reasons for this conclusion are three.

First, retail rate design, of which NEM is an example, is one of four primary policy mechanisms (described in Section V and summarized in Table 3) through which distributed solar and storage are deployed and their benefits realized in U.S. jurisdictions. The other three—grid services tariffs, utility procurements, and deployment incentives—each realize different subsets of the full benefit factor array, and none of the four mechanisms alone is sufficient to realize the complete range of value that distributed solar and storage can provide. A policy framework that addresses only export compensation and rate structure will leave substantial potential value unrealized.

Second, the value of distributed solar and storage is not a fixed quantity that can be determined through a one-time analytical exercise and then used to set a permanent compensation rate. It is a dynamic function of how deployed resources operate (see Section V, "Policy Mechanism Interactions and Portfolio Considerations"), and how they operate is a function of the policy mechanisms that govern them. This means that the design of policy mechanisms is not merely a means of capturing pre-existing value. The mechanisms themselves determine how much value is created and who receives it.

Third, the addition of cost-effective battery storage (see Section II, "The Significance of Affordable Energy Storage") to distributed solar installations transforms the policy design problem in ways that conventional NEM successor analyses do not address. A solar-only compensation framework treats distributed energy resources as passive generation assets whose value is determined by their production profile. A storage-enabled policy framework must treat distributed energy resources as active, dispatchable grid assets whose value is determined by how they are operated, and therefore by the price signals and dispatch obligations that governing policy mechanisms create.

For these reasons, the primary research question accordingly evolved from "what is the value of distributed solar and storage in Washington?" to "what combination of policy mechanisms could maximize the realized benefits of distributed solar and storage in the most cost-effective manner consistent with Washington's clean energy, reliability, and equity objectives?" The Phase 2 research does not answer this question definitively. It does, however, provide the analytical foundation on which that answer can be built.

Findings from the Factor Selection Process

The factor selection process yielded findings that are analytically significant independent of the benefit and cost characterizations that followed. The process of constructing, cross-referencing, characterizing, and selectively reducing the full factor list (Section VI) produced in the interim report, and also provided in Appendix B, included insights about the structure of distributed energy resource value that inform the policy design conclusions in Section X.

The Interim Report's Taxonomy Was More Comprehensive Than Prior Washington-Specific Analysis

Cross-referencing the Interim Report's factor taxonomy against the prior E3 value-of-solar analysis conducted in 2023 for Washington (see Section VI, "Cross-Reference Against the Prior E3 Washington Analysis" and Appendix F) confirmed that the report's list was more comprehensive, particularly in its treatment of distribution system factors, host customer impacts, and societal effects including equity. Given the time and resource constraints under which the E3 analysis was conducted, it appropriately narrowed its scope. Phase 2 research now suggests that some of the excluded factor categories are analytically important and, in certain cases, potentially material in magnitude. Washington policymakers may want to note that a fully comprehensive analysis would need to address a broader range of impacts.

The NSPM Framework Provides Strong Validation But Does Not Resolve Washington-Specific Questions

Cross-referencing the Interim Report's taxonomy against the National Standard Practice Manual (see Section VI, "Cross-Reference Against the National Standard Practice Manual", and Appendix C) confirmed that virtually every factor in the list maps to a recognized NSPM impact category, providing confidence that the taxonomy reflects established analytical practice. The cross-reference also identified gaps, including non-energy impacts, fuel price risk mitigation, and program administrative costs, where future Washington analyses could incorporate NSPM guidance that the Interim Report's framework had not fully explored. However, the NSPM framework does not resolve Washington-specific questions about factor magnitude, data availability, or the interactions between distributed resource deployment and the state's distinctive hydroelectric system. The NSPM provides an important methodological floor, not a complete analytical answer.

Two Washington-Specific Factors Require Analytical Attention Not Available in Out-of-State Context or Precedent

The factor selection process identified two categories of benefit that are particularly important in Washington's energy system context but for which the available analytical precedent from other states provides limited guidance: hydropower ramping reduction and the equity implications of distributed resource policy for Washington's Tribal communities. Both factors require Washington-specific analytical development that was not possible within the project's scope. The absence of well-developed methods for these factors in this analysis should not be interpreted as evidence of their unimportance; it reflects the novelty of the analytical challenge rather than a recommendation about policy significance.

Hydropower ramping reduction

Hydropower ramping reduction was included as a benefit factor despite the absence of any currently implemented U.S. policy mechanism designed to realize it. This is a deliberate departure from the more conventional selection criteria applied elsewhere (see Section VI, "Selection Criteria and Process") in the analysis, which generally favored benefits with established valuation methods and active policy precedent.

The factor was retained for two reasons. First, the underlying physical mechanism is well-supported (see Section VII, "Reduced hydropower ramping benefits"): storage that absorbs midday solar generation and discharges during morning and evening ramp periods can plausibly reduce the steepness of hydropower ramping, which is a real operational cost in a hydro-dominated system. Second, the factor is distinctly relevant to Washington. The Northwest Power and Conservation Council's 2026 Columbia River Basin Fish and Wildlife Program calls for minimizing ramp rates and daily flow fluctuations on the Columbia and Lower Snake during spring and summer fish migration, noting that increased ramping to integrate renewable generation can harm

fish.[190] The limited evidence on how distributed storage might contribute makes this a priority for further research (see Appendix H). Realizing this benefit, however, depends on storage being sized appropriately relative to solar capacity and on the existence of a mechanism that does not yet exist, one that would require close collaboration with dam operators such as BPA and careful attention to ecological constraints on ramping schedules.

Given these conditions, hydropower ramping reduction is best characterized as a prospective benefit (see Section VIII, "Hydropower Ramping Reduction") rather than a currently realizable one. It is included in the analysis as a methodological framework and policy innovation opportunity, not as a benefit with an established valuation or deployment pathway.

Equity Implications: DERs and Tribal Communities in Washington State

During the 2026 wildfire season, Washington experienced one of its most destructive wildfire seasons on record, and Tribal lands have been significantly affected. A federal emergency declaration has been issued that includes six counties and several Washington Tribes – the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Colville Reservation and the Spokane Tribe of Indians.[191] Power outages have occurred in communities affected by these fires, indicating that wildfire risk and electricity reliability on Tribal lands are related factors rather than separate issues (see also Section VIII, "Increased Host Customer Resilience" and "Hydropower Ramping Reduction", Equity Perspective).

Distributed energy resources can help mitigate this gap in electric reliability. Long transmission lines and centralized feeder infrastructure are vulnerable to wildfire damage and are costly and time-consuming to rebuild across the remote terrain many Washington reservations occupy. Community-scale solar, battery storage, and microgrids sited at critical facilities – Tribal offices, schools, clinics, emergency shelters – can maintain essential services when the surrounding grid fails, and can typically be deployed or restored faster than utility-scale transmission infrastructure.

Washington Tribes have pursued this approach using state Climate Commitment Act funding, and recent funding from the Washington Department of Commerce was awarded for Tribal clean energy and resilience projects, including microgrid and solar-plus-storage aimed at reducing outage frequency and improving infrastructure resilience against wildfire and extreme weather. The scale of impact during the current fire season indicates that additional investment in this area may be warranted. For Tribal communities in wildfire-prone areas of the state, DERs function as a resilience measure in addition to their cost and workforce benefits, with the specific effect of maintaining power, water systems, and emergency communications for communities where existing grid infrastructure has historically been limited and wildfire risk is a recurring factor.

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[190] Northwest Power and Conservation Council. (2026, June 16). Council approves 2026 Columbia River Basin Fish and Wildlife Program. https://www.nwcouncil.org/news/2026/06/16/council-approves-2026-columbia-basin-fish-and-wildlife-program

[191] Federal Emergency Management Agency. (August 4, 2026) *How FEMA's Emergency Assistance Benefits Washington Wildfire Response*. https://www.fema.gov/fact-sheet/how-femas-emergency-assistance-benefits-washington-wildfire-response.

The Representative Set of Factors Demonstrates Methodological Range Without Claiming Completeness

The ten factors selected for analysis in this report (listed in Table 4, Section VI, “Selected Factors”) -eight benefit factors and two cost factors-were chosen to demonstrate the full range of quantification approaches Washington policymakers will need to apply across the complete factor list. They do not constitute a complete accounting of all relevant benefits and costs. Future Washington-specific analyses designed to inform specific regulatory proceedings would benefit by the incorporation of the full factor taxonomy, using the methodological framework in this report as a starting point for factors where those approaches are applicable and developing additional methods for factors not addressed here (excluded factors are documented in Appendix I).

Findings on Benefit Realization by Mechanism

These findings draw on the analysis in Section VIII and are summarized in Table 5. The analysis focused on realizing benefits produced findings at two levels: factor-specific findings about how each benefit factor is realized under each mechanism, and cross-cutting findings about the structural relationships between mechanism design and benefit realization that hold across multiple factors.

Storage Attachment Is the Single Most Consequential Variable for Benefit Realization

Across every benefit factor in the representative set, storage-enabled installations realize higher or equal benefit levels (see the “Storage-Enabled Installations” discussion for each factor in Section VIII) compared to solar-only installations, and in several factors the difference is categorical rather than marginal. Solar-only installations realize little or no bulk capacity value, little or no distribution capacity value, and no host customer resilience benefit regardless of which mechanism governs them. Storage-enabled installations can realize substantial benefits in all three categories under appropriate mechanism designs. For avoided energy costs, storage's ability to perform temporal arbitrage substantially increases realized benefit relative to the passive coincidence available to solar-only systems.

The policy implication is unambiguous: mechanism design could, to the greatest extent possible, be structured to promote the attachment of storage to solar installations. This means not merely allowing paired storage to qualify for the same compensation as solar-only systems, but actively creating economic incentives that make storage attachment financially attractive, through TOU rate differentials that reward temporal arbitrage, grid services compensation that is available to storage-enabled but not solar-only resources, and incentive programs that provide enhanced rebates for storage paired with solar. As solar penetration increases and the marginal value of solar-only generation declines, the case for storage attachment grows stronger over time.

Two caveats temper this recommendation. First, policy design can shape the incentive to adopt storage, but it cannot override the underlying economics: storage costs have declined substantially but remain a real constraint, and the degree to which any of these mechanisms actually moves adoption will depend on where storage costs sit relative to the incentive offered. Mechanism design should therefore be understood as improving the odds of storage attachment, not guaranteeing it. Cost trends will continue to be meaningful.

Second, these incentives need to be sized to reflect the actual value storage provides, not set arbitrarily high simply to drive adoption. A TOU rate differential could track the real benefit of shifting load at that time-- avoided ramping, avoided peak capacity costs, distribution deferral, and so on--rather than being inflated purely as a lever to drive certain kinds of behavior. The same discipline applies to enhanced rebates and grid services compensation: the incentive level should be calibrated to the benefit storage attachment delivers in a given context, not set independently of it. Incentives designed this way remain justified on their own economic terms, whereas incentives detached from underlying benefit risk over-compensating storage relative to the value it provides.

No Single Mechanism Realizes All Benefit Factors Effectively

The analysis shows that no single policy mechanism is sufficient to realize the full array of potential distributed solar and storage benefits. Instead, the mechanisms are structurally complementary, each best suited to realizing a distinct subset of benefit factors:

- **Retail rate design** is most effective at realizing avoided energy costs from storage-enabled installations through temporal arbitrage incentives, but provides limited ability to capture distribution-tier value or to direct deployment toward LMI households. (See Section V, "Retail Rate Design")
- **Grid services tariffs** are most effective at realizing bulk and distribution capacity costs from storage-enabled installations, particularly where tariff design includes explicit capacity value components and locational differentiation, but do not address host customer resilience or distributional, equitable economic impacts without explicit design features. (See Section V, "Grid Services Tariffs")
- **Utility procurements** are most effective at realizing both bulk and distribution capacity costs from storage-enabled installations where capacity provision is specified as the primary contracted service, and offer the greatest potential for net positive ratepayer value as the market matures, but are slow, transaction-intensive, and poorly suited as the primary driver of broad-based distributed resource deployment. (See Section V, "Utility Procurements")
- **Deployment incentives** are most effective at realizing host customer resilience and improved economic wellbeing for targeted populations, and are the mechanism most directly capable of driving the deployment volume on which market price impacts (DRIPE) depend, but do not by themselves ensure that deployed assets operate in ways that realize energy or capacity benefits. (See Section V, "Deployment Incentives")

This complementarity is not a design failure; it reflects the genuine diversity of the value streams that distributed solar and storage can provide, each of which has different temporal, locational, and behavioral characteristics that call for different policy instruments. The appropriate policy response is not to choose among the mechanisms but to design a portfolio that combines them in ways that maximize aggregate benefit realization at minimum aggregate cost.

Mechanism Design Quality Matters as Much as Mechanism Choice

The benefit realization analysis reveals that the quality of mechanism design–the precision with which price signals, dispatch protocols, compensation structures, and eligibility conditions are calibrated to the actual value of the targeted benefits–is as consequential as the choice of which

mechanism type to employ. A well-designed retail rate structure with accurate TOU differentiation and value-reflective export compensation realizes substantially more avoided energy cost benefit than a poorly designed rate structure with flat rates and full-retail-rate NEM compensation. A grid services tariff with precise dispatch protocols and capacity value components aligned with actual system peak periods realizes substantially more bulk capacity benefit than a generic demand response program with static event windows. The policy design task is not simply to select a mechanism type but to design it well.

Several mechanism design features emerged (see Section VIII for the mechanism-by-factor analysis) from the analysis as particularly consequential for benefit realization:

- **Time-varying rates**: Capturing avoided energy costs requires that both the prices customers pay for electricity and the credits they receive for exports vary by time of day, following actual wholesale cost patterns.
- **Capacity payments:** Paying storage specifically for discharging during peak demand periods captures the value of avoided generating capacity. Time-of-use rate differences alone are not enough to do this.
- **Location-based compensation:** Distribution savings depend on location, so statewide rates cannot capture them. Grid services tariffs and deployment incentives that pay more where distributed resources relieve strain on the local grid can.
- **Operational conditions on incentives:** Requiring incentive recipients to enroll in a grid services program or to install equipment that can provide backup power ensures that incentivized systems deliver the benefits the incentive was meant to secure. (See Section V, “Deployment Incentives”)

Hydropower Ramping Reduction Requires New Mechanism Design

The hydropower ramping reduction benefit factor is unique in that no currently implemented U.S. policy mechanism has been specifically designed to realize it (see Section VII, “Reduced Hydropower Ramping Benefits”, and Appendix H). This report proposes a methodological framework for quantifying this benefit, and identifies the general mechanism design features that would be required to realize it—a grid services tariff or procurement program that compensates storage specifically for dispatch during hydropower ramping periods. Washington is the jurisdiction best positioned to develop and pilot such a mechanism, given the centrality of hydroelectric generation to the state's electricity system. The development of this mechanism design, while challenging, represents a genuine policy innovation opportunity for Washington that no other state has yet pursued.

Market Price Impacts Are a Portfolio-Level Co-Benefit, Not a Mechanism-Level Target

Market price impacts (DRIPE) (see Section VII, “Reduction in Market Prices”, and Section VIII, “Market Price Impacts”) stand apart from the other benefit factors in this set. They result from the total amount of distributed resources deployed, not from anything a single resource or mechanism does. For that reason, Washington’s cost-effectiveness analysis could treat DRIPE as a portfolio-wide co-benefit, calculated for the full fleet of deployed resources across all mechanisms rather than as a goal for individual mechanism design. The mechanisms with the most influence on DRIPE are those that drive most deployment, mainly deployment incentives and favorable rate design.

Findings on Cost Incidence by Mechanism

These findings draw on Section IX and are summarized in Table 6. The cost factor analysis produced findings that are analytically important for policy design and that carry significant equity implications in Washington's specific context.

The Cost Shift Is the Dominant Cost Concern and Is Concentrated in Retail Rate Design

Of the cost factors analyzed, the cost shift to non-participating ratepayers is the most significant in magnitude, the most directly policy-controllable, and the most contested analytically. The cost shift is concentrated in the retail rate design mechanism: under traditional full-retail-rate NEM, any difference between the bundled retail rate export credit and the utility's actual avoided supply cost constitutes a systematic transfer from non-participating ratepayers to participating customers. The magnitude of this transfer varies substantially across jurisdictions and analytical methodologies, ranging from zero to approximately $0.08 per kilowatt-hour of exports in documented proceedings in other states (see Section V, “Retail Rate Design”).

A critical finding from this project is that the magnitude of the cost shift depends fundamentally on what system benefits are included in the benefit-cost analysis (see Section IV, “How This Project Addresses Cost Shift”, Section V, “Minimizing Cost Shift”, and Appendix E). Analyses that incorporate the full range of system benefits that NEM participants provide, including peak capacity contributions, transmission congestion relief, and environmental benefits not captured in standard avoided cost methodologies, produce substantially smaller cost shift estimates than analyses that rely on narrow avoided cost metrics. Washington's NEM successor regulatory proceedings must be designed to accommodate comprehensive benefit valuation; proceedings that use narrow avoided cost methodologies risk overstating the cost shift and thereby producing export compensation structures that are more restrictive than the underlying economics justify.

Increased System Costs Can Keep System Cost Increases Manageable for Storage-Enabled Installations With the Appropriate Mechanism Design

Storage-enabled installations have much lower net impacts on bulk and distribution system costs than solar-only installations, but only when mechanisms guide how the batteries operate. (see Section IX, “Other Cost Factors: System Costs”) Without dispatch requirements or TOU rates, many batteries charge at the same time, creating new peaks on local distribution circuits. That raises system costs without any offsetting peak reduction. Under a combination of TOU rates and grid services programs, the same batteries can charge at times that avoid creating new peaks and discharge during local peak periods. That approach keeps net system costs low and maximizes distribution capacity benefits.

The policy implication is that the system cost risks of storage depend on how mechanisms are designed, not on the technology itself. Deploying storage at scale without mechanisms that shape how it operates will lead to avoidable cost increases. Well-designed retail rates, targeted grid services programs, and coordinated incentive programs, used together, can limit those increases while capturing more of the benefits of storage.

The Cost Shift and Increased System Costs Interact Through Rate Design

Cost shift and increased system costs are linked through retail rate design, which makes them hard to analyze separately and raises equity concerns (see Section V, “Retail Rate Design”, and Section IX, “Characterizing Costs by Mechanism”). When a utility raises rates to make up revenue lost to net metering cost shift, rather than changing export compensation, electricity prices rise for all customers, including low- and moderate-income (LMI) households that can least afford it. When a utility instead limits cost shift by recovering more fixed costs through customer charges, it reduces cost shift but places a fixed burden on low-usage customers, which is regressive in a different way.

Understanding these tradeoffs requires analyzing cost shift, system cost impacts, and who bears the cost, together. No single cost factor or benefit-cost test can capture all three. Washington's regulatory proceedings for NEM successor tariffs could be structured to require an integrated analysis as a standard deliverable.

Deployment Incentive Cost Shifts Are Potentially Regressive in the Absence of LMI Targeting

Ratepayer-funded deployment incentive programs generate cost shifts directly: a per-kilowatt-hour surcharge on all customers’ bills pays for subsidies to customers who install solar and storage. If the incentive exceeds the benefits a project provides to the grid, and participants are mostly higher-income, as has historically been the case for solar incentive programs without deliberate equity-focused design, the program becomes a regressive transfer from lower-income ratepayers to higher-income program participants.

Several design tools limit this risk (see Section V, “Deployment Incentives”). They include setting incentives at the minimum needed to make projects viable for deployment, using declining block structures that reduce incentives as technology costs fall, and offering larger incentives to low- and moderate-income participants.

Another approach addresses the underlying mismatch more directly: limiting the ratepayer-funded portion of the incentive to the value of the benefits the system is expected to provide to the grid or to other ratepayers. Moreover, where policymakers wish to encourage adoption beyond what that benefit-based incentive alone would support, the additional amount could be funded through a non-ratepayer source, such as general tax revenue or a dedicated appropriation. This approach confines the ratepayer-funded portion of the program to cost-justified levels by construction, while still allowing broader adoption goals to be pursued through funding mechanisms that don't rely on a regressive cross-subsidy from non-participating ratepayers.

Cross-Cutting Findings on Mechanism Design and Portfolio Considerations

The most important findings of this report are not factor- or mechanism-specific but relate to the structural relationships among mechanisms and the design principles that govern the portfolio as a whole.

Policy Mechanism Choices Determine How Much Value Is Realized, Not Just How It Is Distributed

Policy mechanisms help determine how much value exists. A solar-plus-storage system on a rooftop in Washington can potentially provide avoided energy costs, capacity, distribution system benefits, resilience, and more. How much of that potential is realized, and how much ratepayers and communities benefit, depends almost entirely on the policies that shape how the system operates. The same equipment can produce very different results for ratepayers, the grid, and local communities under different policies.

For policymakers moving forward, a more useful question than "What is the value of solar and storage?" is "What combination of mechanisms will lead these resources to operate in ways that create the most value for Washington?" Answering that question requires looking at how mechanisms work together, not just at each one on its own.

Many States Have Implemented Single Mechanisms Focused on Single Benefits

Most states covered in the review (see Section III and Appendix D) started with a single mechanism aimed at one or two benefits, such as an incentive program for solar deployment, a special retail rate for storage, or a procurement program for distribution peak reduction. Several states have since added complementary mechanisms. Cost-effectiveness studies in the literature follow the same pattern, evaluating whether individual programs deliver specific benefits rather than whether a combination of mechanisms delivers the full range of benefits. (See Section V, "Policy Mechanism Interactions and Portfolio Considerations")

This pattern reflects how distributed energy policy developed. It began with net metering as a simple, broadly applicable tool and added more sophisticated approaches over time as adoption grew and technology costs fell. It does not reflect a conclusion that portfolio approaches are less effective. Instead, it suggests that portfolio approaches are still being developed in other states.

The Sequencing and Coordination of Mechanism Design Matters

The mechanisms in a distributed energy resource policy portfolio are not independent. They affect one another, shaping both the realized benefits and who bears the cost. Retail rates influence how systems installed through incentive programs operate. Grid services programs draw value from systems that incentives made affordable. Procurement programs depend on a large enough base of installed systems, built through incentives and favorable rates, to make aggregation practical. Because of these links, the order and coordination of mechanisms matter as much as the design of any single use. (see Section V, "Policy Mechanism Interactions and Portfolio Considerations", and Table 3)

The findings suggest a general order for Washington's policy development:

- **Retail rate design reform comes first**. Moving from full retail-rate net metering to compensation that reflects when and where distributed resources provide value is the foundation, because rates affect how every system in the state operates, whatever other mechanisms are in place.

- **Grid services tariffs follow or accompany rate reform**. They pay for capacity and location-specific value that rates alone cannot capture, and they establish the framework for paying distributed resources based on performance.
- **Deployment incentives are sized to fit the compensation already available**. Given the revenue a system can earn from rates and grid services, incentives are set at the minimum needed to make the investment worthwhile for the customer or developer. They also require incentivized systems to enroll in grid services programs, linking them to the programs that guide their operation.
- **Utility procurement becomes most cost-effective later,** once enough distributed resources are installed to make aggregation practical and the aggregation market is mature enough for competitive bidding to reveal true prices.

Procurements Have the Greatest Potential for Net Positive Ratepayer Value as the Market Matures

Of the four mechanisms, utility procurement has the most potential to deliver benefits greater than the costs (a benefit-cost ratio above 1.0) as the distributed energy market matures (see Section V, "Utility Procurements"). When competition works well, procurement reveals the lowest price at which aggregators can profitably provide the grid services a utility needs. As costs fall for acquiring customers, integrating, and dispatching, that price could drop below the value of the services, creating net savings for ratepayers. No other mechanism is structured to produce this result on its own: retail rates are set administratively, grid services tariffs are usually priced at the value of the service (a ratio of 1.0 by design), and deployment incentives are set at the minimum needed for projects to be viable, not at the value they enable.

This does not mean procurement is the right primary mechanism for Washington now. It does mean procurement could be a planned part of Washington's policy framework, with potentially a larger role to play as the market develops.

The Value of Incentive Programs Is Properly Assessed at the Portfolio Level

A recurring finding across the benefit and cost analyses is that deployment incentives are hard to judge for cost-effectiveness on their own. An incentive that funds a storage system later dispatched through a grid services program to reduce peak demand delivers far more system value per incentive dollar than the same incentive evaluated as if the battery only lowered its owner's bill. On the other hand, an incentive that funds storage with no grid services enrollment or operating requirements produces value mainly for the host customer, through bill savings and backup power, and may not be cost-effective when weighed against its cost to ratepayers.

The policy implication is that incentive programs work best when designed together with the retail rates and grid services tariffs that will guide how incentivized systems operate (see Section V, "Deployment Incentives", and Section IX, "Characterizing Costs by Mechanism"). An incentive designed without regard to those mechanisms is likely to be less cost effective than intended, and its cost effectiveness can't be accurately measured without accounting for the revenue and operation those mechanisms make possible.

Crediting incentives with grid services value risks double counting. If both the incentive program and the grid services program claim the same battery's peak capacity value, total benefits are overstated. Evaluating the mechanisms together, and counting each benefit once against their combined costs, avoids this risk.

Findings on the State of the Evidence Base and Directions for Further Research

The project research reviewed state regulatory and academic literature (summarized in Appendix D) on valuing distributed energy resources and designing policy mechanisms. Its findings on the state of that evidence are relevant to Washington's policy development.

The Evidence Base Is Rich for Some Factors and Mechanisms, Thin for Others

Methods for estimating avoided energy costs and avoided bulk capacity costs are well developed, with several documented approaches that apply to Washington (the research notes in Section VIII identify evidence gaps factor by factor). Evidence on market price impacts, avoided distribution capacity costs, and customer resilience is moderate. Methods exist in several states but need calibration for Washington. Evidence on hydropower ramping reduction and on the equity dimensions of several factors is limited in Washington and needs more research, including the implications of hydropower policy for Tribal communities and workforce equity in solar deployment.

Cost-Effectiveness Studies Have Evaluated Individual Programs, Not Mechanism Portfolios

As noted in this section, cost effectiveness studies focus on individual programs and specific benefits, not on combinations of mechanisms and the full range of benefits. The research found extensive guidance on calculating, for example, avoided energy costs under net metering or avoided capacity costs under a virtual power plant contract (see Appendix D). It found very little on evaluating the combined cost-effectiveness of rate reform, a grid services program, and an incentive program applied to the same fleet of distributed resources. Developing methods for this kind of portfolio-level analysis is a major research need, both for Washington and for the field.

California's NEM 3.0 Experience Is Instructive but Not Directly Transferable

California's experience with NEM 3.0 (see Section II, "Historical Development of Net Energy Metering Policy", and Section V, "Retail Rate Design"), which sharply cut export compensation for new solar customers and caused significant short-term market disruption, is the most extensive recent example of what happens when a net metering successor tariff is designed aggressively. Research for this project used that example to inform the examination of rate design tradeoffs. But California differs from Washington in market structure, electricity rates, solar adoption, and regulation, which limits how directly its results apply. California's experience is best treated as a source of cautionary lessons, especially about transition planning, market certainty, and how export compensation interacts with storage incentives.

Washington-Specific Data and Modeling Are Required for Regulatory Implementation

The methods described in this report need Washington-specific data to produce the estimates required for regulatory proceedings (Appendix G lists Washington State utilities). Those data include utility load profiles, avoided cost schedules, distribution hosting capacity maps, hydroelectric dispatch data, and household income and energy burden by service territory. Most of these data are not publicly available in usable form, and gathering and validating them will take significant effort that future proceedings will have to plan for, including the building of a data infrastructure to support future energy-resource analyses.

The Hydropower Ramping Reduction Factor Represents a Priority Research Investment

Hydropower ramping reduction has a combination of potential policy significance, given how central hydropower is to Washington's electricity system (see Appendix H). However, it is the least developed analytically. This report could be a starting point for quantifying this benefit in ways that are tested against Washington hydropower operating data. Developing a rigorous Washington-specific method, in consultation with the Bonneville Power Administration, public utility districts, and affected Tribal nations, is an important research investment for future phases of distributed energy resource policy development in the state.

Consolidated Findings Summary

Table 7 consolidates the principal findings of Phase 2 research, organized by finding category, with a summary statement of each finding and its primary policy implication. This table is intended as a reference for readers who wish to locate the detailed analysis supporting any particular finding in the preceding sections.

Table 7. Summary of Research Findings

Category	Summary Statement	Primary Policy Implication
Benefit Realization	Storage attachment is the single most consequential variable for benefit realization. Storage-enabled installations realize higher or equal benefits than solar-only across every factor.	Mechanism design should actively promote storage attachment, not merely permit it. Economic incentives for pairing storage with solar should be a central feature of Washington's policy portfolio.
	No single mechanism realizes all benefit factors effectively. The four mechanisms are structurally complementary, each best suited to a distinct subset of benefits.	Washington's distributed energy resource policy framework should be designed as a portfolio of mechanisms, not a single instrument.
	Mechanism design quality matters as much as mechanism type. TOU differentiation, capacity value components, locational differentiation,	Washington's regulatory proceedings must invest in detailed mechanism design, not only mechanism type selection.

Category	Summary Statement	Primary Policy Implication
	and operational requirements are critical design features.	
	Hydropower ramping reduction requires new mechanism design not yet implemented in any U.S. jurisdiction.	Washington should develop and pilot a mechanism specifically targeting hydropower ramping reduction as a priority policy innovation.
	Market price impacts (DRIPE) are a portfolio-level co-benefit of deployment volume, not a factor that individual mechanisms can target.	DRIPE should be incorporated as an aggregate portfolio-level benefit in Washington's cost-effectiveness analysis framework.
Cost Factors	The cost shift is the dominant cost concern and is concentrated in retail rate design. Its magnitude depends fundamentally on what system benefits are included in the analysis.	Washington's NEM successor proceedings must use comprehensive benefit valuation. Narrow avoided cost methodologies risk overstating the cost shift.
	Increased system costs from storage are manageable under appropriate mechanism design but can be significant without dispatch requirements and operational constraints.	Storage deployment at scale should be accompanied by mechanism designs that include operational constraints, not only deployment subsidies.
	The cost shift and increased system costs interact through rate design and must be analyzed integrally, not separately.	Regulatory proceedings should require integrated cost-shift and system cost analysis, not sequential separate analyses.
Portfolio Design	To date, states have implemented single mechanisms for single benefits. Washington has the opportunity and the mandate to implement a coordinated portfolio approach.	Washington's policy roadmap should explicitly address mechanism coordination and sequencing, not only individual mechanism design.
	Utility procurements have the greatest potential for net positive ratepayer value (B/C > 1.0) as the distributed resource market matures.	Procurement program development should be an explicit component of Washington's distributed energy resource policy roadmap.
	Incentive program cost-effectiveness cannot be assessed in isolation; it must be evaluated in combination with the operational mechanisms that govern the behavior of incentivized assets.	Incentive program design should be developed in coordination with retail rate and grid services program design, not as a standalone instrument.
Evidence Base	Documented cost-effectiveness studies evaluate individual programs and specific benefits; portfolio-level cost-effectiveness	Development of portfolio-level cost-effectiveness analysis frameworks is

Category	Summary Statement	Primary Policy Implication
	frameworks do not yet exist in the literature.	a priority research need for Washington and for the field.
	Washington-specific data and modeling are required for regulatory implementation; the necessary data infrastructure does not yet exist in systematic public-record form.	The Department of Commerce, UTC, and Washington utilities should begin developing the data infrastructure needed to support Washington-specific distributed energy resource analysis.

What This Research Does and Does Not Provide

This research provides:

- A comprehensive taxonomy of benefit and cost factors (Appendix B) associated with distributed solar and storage in Washington State, cross-referenced against established analytical frameworks and prior Washington-specific analysis.
- A structured methodology for selecting a representative subset of factors for analytical demonstration, with documented rationale for inclusions and exclusions (Section VI and Appendix I).
- Documented analytical methods for quantifying each of the ten factors in the representative set (Section VII), drawn from state-level regulatory proceedings and academic literature, with assessment of their applicability in the Washington context.
- Qualitative characterizations of how effectively each of the four primary policy mechanisms tends to realize each benefit factor, for both solar-only and storage-enabled installations, with documented support from state-level examples.
- Qualitative characterizations of the cost incidence of each mechanism across the two cost factors, with assessment of mechanism design features that can mitigate cost generation.
- A set of cross-cutting design principles for Washington's distributed energy resource policy portfolio, grounded in the benefit and cost factor analyses.
- Identification of research gaps and data development needs that must be addressed before Washington-specific quantitative estimates can be produced for use in regulatory proceedings.

The research does not provide:

- Washington-specific quantitative estimates of the dollar value of any benefit factor attributable to distributed solar and storage deployment. Such estimates require Washington-specific data inputs and modeling that exceed the project scope.
- A recommendation for specific export compensation rates, incentive levels, or procurement contract terms. These determinations require the Washington-specific quantitative analysis. This project lays the methodological groundwork for those analyses.
- A definitive comparison of the cost-effectiveness of alternative Washington policy mechanism designs. Such comparison requires portfolio-level cost-effectiveness modeling using Washington-specific data.

- A complete benefit-cost analysis of any specific Washington utility's distributed energy resource program or NEM successor tariff proposal. This project provides the methodological framework for such analyses, but the analyses themselves must be conducted using utility-specific data in formal regulatory proceedings.

APPENDIX A: GLOSSARY OF KEY TERMS

This glossary defines technical and policy terms used throughout this report.

Ancillary Services	Grid support services—including frequency regulation, spinning reserve, and voltage support—necessary to maintain reliable grid operation. Distributed energy resources, particularly storage, can provide ancillary services and may be compensated through grid services tariffs.[192]
Attachment Rate	The share of newly installed rooftop solar systems that include co-located battery storage. Nationally, the residential solar attachment rate rose from 9% in 2023 to 25% in 2024, reflecting rapid growth in solar plus storage adoption.[193]
Avoided Cost	The cost that an electric utility avoids incurring—whether for energy, capacity, transmission, or distribution—as a result of distributed energy resource generation or demand reduction. Avoided cost is a common basis for pricing exported energy in NEM successor tariffs and grid services programs.[194]
Avoided Energy Cost (AEC)	The reduction in energy procurement costs resulting from electricity generated, stored, or conserved by distributed energy resources (DERs), thereby avoiding the need for a utility or customer to purchase or produce that energy from other sources. Avoided energy costs are typically calculated as the amount of energy avoided (kWh) multiplied by the applicable energy price. The value varies depending on perspective: customer-side calculations generally use retail electricity rates, while utility-side calculations use marginal or wholesale energy costs. Time-varying avoided energy costs are commonly evaluated on an hourly basis to reflect changing market conditions and system demand.
Behind-the-Meter (BTM)	The utility customer's side of an electricity meter. BTM assets relevant to this study include systems that generate, store, and export electricity, locally consume generated energy, or import energy from the grid. Contrast with front-of-the-meter (FTM), where systems supply power directly to the grid.
Benefit-Cost Analysis (BCA)	A systematic comparison of the total quantified benefits and costs of a proposed resource investment or policy, typically expressed as a benefit-to-cost ratio. An investment is considered cost-effective when the ratio of

[192] Federal Energy Regulatory Commission. (2007). *Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion*. A Study Pursuant to Section 1817 of EPACT 2005. https://www.ferc.gov/sites/default/files/2020-04/1817_study_sep_07.pdf
[193] Lawrence Berkeley National Laboratory. (2025). *Distributed Solar & Storage – 2025 Data Update*. https://emp.lbl.gov/sites/default/files/2025-10/Distributed%20Solar%20%26%20Storage-2025%20Data%20Update.pdf
[194] Federal Energy Regulatory Commission. (2025). *PURPA Qualifying Facilities – Avoided Cost*. 18 C.F.R. § 292.101(b)(6). https://www.ferc.gov/qf

	benefits to costs equals or exceeds 1.0. BCA can be conducted from multiple perspectives—utility, ratepayer, participant, or societal.[195]
Benefit Factor	A discrete, quantifiable (or otherwise estimable) category of value that a distributed energy resource can deliver to ratepayers, utilities, or society—such as avoided energy costs, avoided capacity costs, or resilience benefits. Benefit factors collectively constitute a value stack.
Clean Energy Transformation Act (CETA)	Washington State law (RCW 19.405) requiring all retail electric sales to be greenhouse-gas neutral by 2030 and 100% non-emitting by 2045. CETA mandates that utilities pursue cost-effective energy efficiency and includes equity provisions requiring equitable distribution of clean energy benefits.
Climate Commitment Act (CCA)	Washington State law (Chapter 70A.65 RCW, enacted 2021) establishes a cap-and-invest program that requires major greenhouse gas emitters to purchase allowances from a shrinking pool, creating a financial incentive to reduce emissions. At least 35% of revenues must directly benefit vulnerable populations.
Community Solar	Washington's Community Solar Law, in effect since 2017, modified in 2022, and codified in Section 82.16.183 RCW, supports community solar programs with the goal of broadening and diversifying participation in solar energy generation. Eligible projects are limited to 199 kilowatts or smaller and must have at least two subscribers or one low-income service provider subscriber. Community solar provides an access pathway for customers who cannot host rooftop installations, including renters, low-income households, and those in multifamily dwellings, and, while different in some ways, is therefore a relevant complement to BTM solar policy in the state's distributed energy portfolio.
Cost Factor	A discrete, quantifiable category of cost imposed on the electric system or ratepayers as a result of distributed energy resource deployment—such as increased distribution capacity costs or interconnection costs. Cost factors are evaluated alongside benefit factors in a benefit-cost analysis.[196]
Cost Shift	The transfer of electric system infrastructure costs from customers who reduce their grid consumption (e.g., through solar self-generation) to customers who do not. A key concern in net energy metering policy

[195] ICF International. (2018). *Review of Recent Cost-Benefit Studies Related to Net Metering*. Prepared for the U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf

[196] ICF International. (2018). *Review of Recent Cost-Benefit Studies Related to Net Metering*. Prepared for the U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf

	debates, as NEM participants may pay less toward shared grid costs while continuing to rely on the grid.[197]
Customer-Generator	A utility customer who has installed distributed generating capacity on their property. In Washington State, this applies to individual customers with systems up to 100 kW and to qualifying community solar projects, per RCW 80.60.[198]
Demand Response	Programs or technologies that encourage reductions or automatically reduce electricity consumption during periods of high grid demand or high energy prices—for example, cycling air conditioners or shifting industrial loads. Demand response is an example of a distributed energy resource that can reduce peak load.[199]
Dispatchability	The ability to control when and how much electricity a resource generates or discharges, in response to grid needs or operator instructions. Solar generation alone is non-dispatchable (it produces only when the sun shines), but solar plus storage systems are dispatchable because stored energy can be released on demand.[200]
Distributed Energy Resource (DER)	Small- to medium-scale energy technologies that generate or store electricity close to the point of use—such as rooftop solar panels, battery storage systems, small wind turbines, combined heat and power systems, demand response technologies, and electric vehicles used as grid resources.
Distributed Solar	Solar energy systems located close to the point of consumption (e.g., on a residential or commercial rooftop or in a small ground-mounted array), rather than at a centralized utility power plant. These systems are typically connected to the grid and allow for two-way energy flows.
Distributed Storage	Energy storage systems—typically batteries—installed at or near the point of energy generation or use, rather than at large central facilities. These systems can store on-site generation or grid electricity and discharge it to serve customer needs, improve resilience, or support the broader grid.
Demand Reduction Induced Price Effects (DRIPE) [201]	The reduction in wholesale electricity market prices that occurs when energy efficiency, demand response, distributed energy resources, or other load-reducing measures decrease overall electricity demand. By

[197] National Academies of Sciences, Engineering, and Medicine. (2023). *The Role of Net Metering in the Evolving Electricity System*. The National Academies Press. https://doi.org/10.17226/26704
[198] Revised Code of Washington. *RCW 80.60: Net Metering of Electricity*. https://app.leg.wa.gov/rcw/default.aspx?cite=80.60
[199] National Renewable Energy Laboratory. (2024). *Demand Response Analysis. NREL Energy Analysis*. https://www.nrel.gov/analysis/demand-flexibility-value-and-participation-mechanisms
[200] Federal Energy Regulatory Commission. (2007). *Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion*. A Study Pursuant to Section 1817 of EPACT 2005. https://www.ferc.gov/sites/default/files/2020-04/1817_study_sep_07.pdf
[201] Regulatory Assistance Project (RAP). *The Value of Demand Reduction Induced Price Effects (DRIPE)*, 2015, https://www.raponline.org/knowledge-center/the-value-of-demand-reduction-induced-price-effects-dripe/

	lowering demand, particularly during high-cost periods, these resources can reduce the need for more expensive generation and thereby lower market-clearing prices, creating economic benefits for all electricity consumers, not only participants in the demand-reduction program.
Demand Side Grid Support (DSGS)	A grid services program that compensates customer-sited distributed energy resources, particularly battery storage systems, for reducing electricity demand or exporting energy during periods of grid stress, peak demand, or reliability risk. DSGS programs use dispatch signals and performance-based compensation to provide capacity relief and improve grid reliability while avoiding or deferring more costly system investments.
Effective Load-Carrying Capability (ELCC)	A reliability planning metric that measures the amount of additional electric load a resource can support while maintaining the same level of system reliability. ELCC is used to estimate the capacity value of distributed solar, storage, and other resources by assessing their contribution during periods of highest reliability risk. Unlike average energy production, ELCC reflects performance during critical peak-demand hours and typically declines for solar resources as system penetration increases.
Energy Burden	The percentage of a household's gross income spent on energy costs. DOE's Low-Income Energy Affordability Data (LEAD) Tool defines a household with 6% or greater energy burden as a high-burden household. Energy burden disproportionately affects low-to-moderate income households and is a key equity indicator in distributed energy resource policy.[202]
Energy Insecurity	A condition in which a household is unable to adequately meet its energy needs due to cost, unreliability, or physical barriers. Energy insecurity encompasses inability to pay bills, forgoing food or medicine to pay energy costs, and unsafe indoor temperatures.[203]
Energy Rate	The actual price a customer pays for each unit of electricity consumed, typically expressed in cents per kilowatt-hour (¢/kWh). Distinct from an energy rate tariff, which is the full structure of rates, rules, fixed charges, and eligibility conditions.
Environmental Justice	The principle that all people, regardless of race, income, or national origin, should receive equitable protection from environmental hazards and equitable access to environmental benefits—including the benefits of clean energy. CETA, CCA, and the HEAL Act all include environmental justice provisions relevant to distributed solar and storage policy.[204]

[202] U.S. Department of Energy. (2025). *Low-Income Energy Affordability Data (LEAD) Tool*. Office of State and Community Energy Programs. https://www.energy.gov/scep/low-income-energy-affordability-data-lead-tool
[203] U.S. Department of Energy. (2023). *Low-Income Community Energy Solutions*. Office of State and Community Energy Programs. https://www.energy.gov/scep/slsc/low-income-community-energy-solutions
[204] U.S. Environmental Protection Agency. (2024). *Learn About Environmental Justice*. https://www.epa.gov/environmentaljustice/learn-about-environmental-justice

ESHB 2773	Engrossed Substitute House Bill 2773, enacted by the Washington State Legislature in 1998 (effective June 11, 1998) as Chapter 318, Laws of 1998. ESHB 2773 established Washington's net energy metering statute (codified at RCW 80.60) and required electric utilities to offer NEM to customer-generators on a first-come, first-served basis.[205]
FERC Order 2222	A 2020 Federal Energy Regulatory Commission ruling requiring regional wholesale electricity markets to allow aggregations of distributed energy resources to participate and compete alongside traditional power plants. Order 2222 opens stacked revenue opportunities for DER owners and enables VPPs to access wholesale markets.[206]
Grid Services Tariff	A rate schedule that compensates distributed energy resource owners specifically for grid services their systems provide--such as peak demand reduction, voltage support, or frequency regulation--typically priced at or below the value of the service provided. Grid services tariffs are distinct from retail energy rates and generally apply only to electricity exported to the grid.[207]
Healthy Environment for All (HEAL) Act	Washington State law (Chapter 70A.02 RCW, enacted 2021) requiring certain state agencies to incorporate environmental justice into their planning and budgeting decisions. While utilities and the UTC are not directly covered agencies under HEAL, the Act influences equity expectations in electric utility planning.
Hydropower / Hydroelectric Power	Electricity generated by converting the kinetic energy of flowing or falling water. Hydropower provides the majority of Washington State's electricity generation and interacts with distributed solar and storage through ramping requirements, seasonal capacity, and ecosystem impacts. Hydroelectric development has historically displaced and harmed Tribal communities and salmon ecosystems in the Pacific Northwest.
Incentive (as a policy mechanism)	Financial instruments—including tax credits, rebates, upfront grants, and performance-based payments—designed to reduce the cost of deploying distributed solar and storage systems and broaden adoption. In cost-effectiveness evaluation, incentives should be assessed in combination with other policy mechanisms rather than in isolation.[208]

[205] Revised Code of Washington. *RCW 80.60: Net Metering of Electricity*. https://app.leg.wa.gov/rcw/default.aspx?cite=80.60

[206] Federal Energy Regulatory Commission. (2020). *Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs*. https://www.ferc.gov/industries-data/electric/distributed-generation/ferc-order-no-2222

[207] Denholm, et al. (2014). *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. National Renewable Energy Laboratory. NREL/TP-6A20-62447. https://docs.nlr.gov/docs/fy14osti/62447.pdf

[208] Denholm, et al. (2014). *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. National Renewable Energy Laboratory. NREL/TP-6A20-62447. https://docs.nlr.gov/docs/fy14osti/62447.pdf

Installed Capacity (ICAP)	A capacity accreditation metric representing the dependable amount of generating or demand-reduction capacity available to meet peak electricity demand and resource adequacy requirements. ICAP values are used in capacity planning and valuation frameworks to estimate avoided bulk capacity costs and may incorporate the costs of new capacity, operations and maintenance, reserve requirements, and locational considerations.
Integrated Resource Plan (IRP)	A long-range utility planning document that evaluates the full mix of supply- and demand-side resources needed to reliably meet future customer energy needs at least cost, consistent with applicable laws and policies. IRPs inform but differ from Clean Energy Implementation Plans.[209]
Interconnection	The technical and regulatory process by which a customer's distributed generation or storage system is connected to the utility's electric grid, including safety standards, metering requirements, and agreements governing how power flows in both directions.[210]
Kilowatt-Hour (kWh)	The standard unit of electrical energy, equal to consuming or generating one kilowatt (kW) of power for one hour. Energy rates and NEM credits are typically expressed in cents per kilowatt-hour (¢/kWh).[211]
Low-to-Moderate Income (LMI)	Household income classifications—typically defined relative to Area Median Income (AMI) as established by the U.S. Department of Housing and Urban Development—used to identify populations that may face barriers to accessing distributed solar and storage systems, and who may disproportionately benefit from targeted programs and incentives.[212]
Net Energy Metering (NEM)	A billing mechanism allowing electric customers who generate their own electricity—typically via rooftop solar—to receive credits for excess electricity exported to the grid, usually at the full retail rate. In Washington State, NEM is required by RCW 80.60 until either June 30, 2029, or a utility's NEM systems reach 4% of its 1996 peak demand, whichever comes first.
NEM Successor Rate / NEM Successor Tariff	A replacement compensation structure adopted by a utility after reaching the statutory NEM threshold. Successor tariffs may use time-varying rates, avoided-cost-based export credits, or other mechanisms rather than the

[209] National Renewable Energy Laboratory. (2022). *Integrated Resource Planning: Best Practices for Incorporating Distributed Energy Resources*. NREL/TP-6A20-80835. https://www.nrel.gov/docs/fy22osti/80835.pdf
[210] Gorman, W., et al. (2025). *Distributed Energy Resource Integration*. National Renewable Energy Laboratory. NREL/TP-5D00-92436. https://docs.nrel.gov/docs/fy25osti/92436.pdf
[211] U.S. Energy Information Administration. (2025). *Energy Explained: Units and Calculators*. https://www.eia.gov/energyexplained/units-and-calculators/
[212] U.S. Department of Energy. (2025). *Low-Income Energy Affordability Data (LEAD) Tool*. Office of State and Community Energy Programs. https://www.energy.gov/scep/low-income-energy-affordability-data-lead-tool

	full retail rate. PacifiCorp is the first Washington investor-owned utility to have a successor tariff under consideration.[213]
Peak Demand / Peak Load	The maximum level of electricity consumption on a utility's system during a given period—typically measured in kilowatts (kW) or megawatts (MW). Reducing or shifting peak demand is a key potential benefit of distributed solar and storage.[214]
Peak Shaving	The reduction of electricity consumption or export during periods of peak grid demand, typically accomplished by deploying stored energy or reducing load. Peak shaving can defer or avoid costly utility investments in generation and distribution infrastructure.[215]
Performance-Based Incentive (PBI)	A financial incentive that compensates a distributed energy resource based on its measured performance over time rather than solely on its installed capacity. PBIs are commonly paid monthly or annually and are typically tied to actual electricity production (kWh generated), though they may also be linked to delivery of specified grid services. Performance-based incentives provide continuing revenue streams and align compensation more closely with realized system benefits than one-time installation rebates.
Photovoltaic (PV)	Technology that converts sunlight directly into electricity using semiconductor materials. Rooftop solar panels and ground-mounted distributed solar arrays typically use PV technology.[216]
Procurement (as a policy mechanism)	A competitive solicitation process through which a utility or regulator acquires distributed energy resource capacity or services. Procurements—such as virtual power plant programs—can be more cost-effective than administratively set rates because competitive bidding may identify the lowest compensation level needed to attract deployment.[217]
Ramping (Hydropower)	Rapid increases or decreases in hydroelectric generation output to balance grid supply and demand—for example, compensating for periods when solar generation drops. Increased solar plus storage deployment

[213] Revised Code of Washington. *RCW 80.60: Net Metering of Electricity*. https://app.leg.wa.gov/rcw/default.aspx?cite=80.60
[214] Federal Energy Regulatory Commission. (2007). *Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion*. A Study Pursuant to Section 1817 of EPACT 2005. https://www.ferc.gov/sites/default/files/2020-04/1817_study_sep_07.pdf
[215] Denholm, P., et al. (2014). *An Analysis of the Benefits and Challenges of Rooftop Solar Photovoltaics*. National Renewable Energy Laboratory. NREL/TP-6A20-62447. https://docs.nrel.gov/docs/fy14osti/62447.pdf
[216] Gorman, W., et al. (2025). *Distributed Energy Resource Integration*. National Renewable Energy Laboratory. NREL/TP-5D00-92436. https://docs.nrel.gov/docs/fy25osti/92436.pdf
[217] Denholm, P., et al. (2014). *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System.* National Renewable Energy Laboratory. NREL/TP-6A20-62447. https://docs.nlr.gov/docs/fy14osti/62447.pdf

	may reduce the need for hydropower ramping, with potential benefits for river ecosystems and Tribal interests.[218]
Rate Design	The structure and parameters of a retail electricity tariff, including how fixed and variable costs are recovered, how time-of-use pricing is applied, and how exported energy is compensated. Rate design is one of the four primary policy mechanisms for deploying distributed solar and storage. Rates designed to align with time-based cost causation can maximize system benefits from solar plus storage without inducing cost shifts.[219]
Resilience	The ability of a home, community, or grid to withstand, adapt to, and recover from disruptions—including extreme weather events and power outages. Distributed solar plus storage systems can provide backup power and reduce vulnerability to outages, serving as a resilience asset particularly for vulnerable customers and critical facilities.[220]
Solar plus storage	A system that combines solar photovoltaic (PV) generation with co-located energy storage (typically batteries). Storage enables the system to discharge solar energy when production is low or demand is high, transforming a passive generation asset into an active, dispatchable grid resource.
Temporal Arbitrage	The strategy of storing energy when it is cheap or abundant (e.g., midday solar generation) and discharging or selling it when it is more valuable (e.g., during evening peak demand). Battery storage enables temporal arbitrage for distributed solar systems.[221]
Time-of-Use (TOU) Rate	A retail electricity rate structure in which the per-unit price of electricity varies by time of day (and sometimes season), reflecting the varying cost of providing power. TOU rates incentivize customers to shift consumption away from peak demand periods and are a key tool in grid modernization and solar plus storage optimization.[222]
Utilities and Transportation Commission (UTC)	The Washington State regulatory authority with jurisdiction over investor-owned electric utilities. The UTC reviews and approves proposed rate tariffs, including NEM successor tariffs, filed by utilities such as Avista, Puget Sound Energy, and PacifiCorp.[223]

[218] Federal Energy Regulatory Commission. (2007). *Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion*. A Study Pursuant to Section 1817 of EPACT 2005. https://www.ferc.gov/sites/default/files/2020-04/1817_study_sep_07.pdf
[219] National Academies of Sciences, Engineering, and Medicine. (2023). *The Role of Net Metering in the Evolving Electricity System*. The National Academies Press. https://doi.org/10.17226/26704
[220] U.S. Department of Energy, Federal Energy Management Program. (2024). *Distributed Energy Resources for Resilience*. https://energy.gov/femp/distributed-energy-resources-resilience
[221] Denholm, P., et al. (2014). *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System.* National Renewable Energy Laboratory. NREL/TP-6A20-62447. https://docs.nlr.gov/docs/fy14osti/62447.pdf
[222] Ibid.
[223] Revised Code of Washington. RCW 80.60: Net Metering of Electricity. https://app.leg.wa.gov/rcw/default.aspx?cite=80.60

Value Stack	A compilation of the multiple distinct benefit factors that a distributed energy resource can provide—spanning energy, capacity, grid services, environmental, and societal values. The values are aggregated to estimate the total potential worth of the resource. A complete value stack informs rate design and other policy mechanisms.
Value of Distributed Energy Resources (VDER)	New York's distributed energy resource compensation framework that replaces traditional net energy metering with a value stack methodology. VDER compensates DER exports based on multiple components of system value, including energy value, capacity value, environmental value, demand reduction value (DRV), and locational system relief value (LSRV). The framework is designed to align compensation more closely with the time- and location-specific benefits that distributed resources provide to the electric system.
Virtual Power Plant (VPP)	An aggregation of distributed energy resources—typically customer-sited solar, batteries, and smart devices—coordinated through software to operate collectively as a dispatchable grid resource. VPP programs are a form of procurement that can deliver peak shaving, frequency regulation, and other grid services.

APPENDIX B: BENEFIT AND COST FACTORS

Appendix B presents the complete taxonomy of benefit and cost factors identified in the Phase 1 Interim Report, organized by energy system category—generation, transmission, distribution, host customer, and societal. The eight benefit factors and two cost factors selected for detailed analysis in this report represent a methodologically representative subset of this larger list, chosen to exercise the full range of analytical approaches the project developed rather than to provide exhaustive quantification of every category. The full taxonomy is included here to document the complete landscape of potential DER value and cost considerations from which that subset was drawn.

Table B. Phase 1 Full List of Benefit and Cost Factors

Generation (Ratepayers)
Avoided capacity
Avoided energy
Avoided Environmental Compliance costs (e.g. Reduction of criteria pollution emissions in excess of permit limits).
Avoided generation O&M costs
Avoided cost of purchasing energy from renewable resources for CETA compliance
Resource diversity
Fuel hedging
Market Price reductions
Avoided costs of Ancillary services
Transmission (Ratepayers)
Avoided transmission capacity
Avoided line losses
Improved Bulk System Reliability
Improved Bulk System Resilience
Distribution (Ratepayers)
Avoided distribution capacity
Avoided Distribution System Losses
Avoided Distribution O&M
Avoided Distribution Voltage / Power Quality costs
Improved Distribution system reliability
Improved Distribution system Resilience (e.g. Support for de-energizing power lines for reducing fire risk)
Other System Benefits
Reduced Credit and Collection Costs
Reduced Risk

Host Customer
Reduced utility bills
Improved Site Resilience
GHG reduction (supports customer electrifying load)
Incentives
Reduced risk
Increased Asset Value
Improved Productivity
Improved Economic well-being
Increased Comfort
Improved Health & Safety
Increased Empowerment
Increased Pride
Societal
Resilience
GHGs
Other Environmental (Reduction of Criteria and hazardous air pollutants (e.g. SO2, NOx, PM) due to reduced dispatch of generation plants that use carbon-based fuels)
Public Health
Energy Security
Water Use
Land Use (including Tribal Lands)
Reduction in ramping of hydroelectric dams
Local tax revenue
State Tax revenue
Workforce development
Jobs
Low income: Society (e.g. Poverty alleviation, env justice, reduced home foreclosures, etc)

APPENDIX C: NSPM COMPARISON TO WSAS PHASE 1 INTERIM REPORT

Appendix C compares the WSAS Interim Report's benefit-cost framework against the National Standard Practice Manual (NSPM). Table C-1 shows the overall alignment across benefit factors evaluated by both documents, with many factors mapping directly onto a corresponding NSPM-defined category and section. Table C-2 identifies where gaps between the WSAS Phase 1 Interim Report and NSPM exist, including elements related to non-energy impacts, fuel price risk mitigation, market participation revenues, program administrative costs, and DER interaction effects. Table C-3 provides an overview of where WSAS and NSPM definitions partially overlap but diverge in specificity or methodology, creating uncertainty about how these benefits should be measured or applied. Together, these findings support the interim report's recommendation that WSAS Phase 2 adopt a more comprehensive, multi-dimensional benefit-cost framework consistent with NSPM standards, capturing both utility-system and broader societal impacts.

The NSPM offers a comprehensive framework that validates nearly every benefit factor listed in the WSAS Interim Report (Table 4 therein). Several WSAS Interim Report factors, like equity, resilience, and market effects, are treated as non-utility impacts in NSPM, but are still recommended for inclusion when relevant to jurisdictional policy goals. This alignment strengthens the case for this project to adopt a multi-dimensional BCA framework that reflects both utility system and societal impacts.

Table C-1. WSAS Phase 1 Interim Report Cross-Referenced Benefit and Cost Factors with NSPM Definitions

WSAS Interim report benefit factor	WSAS Interim Report Definition/Description	NSPM Definition/ Description	Section in NSPM
Air Quality Improvements	*"The reduction in emissions of pollutants such as NOx, SOx, and PM2.5, leading to improved public health."*	*"DERs can reduce emissions of criteria pollutants (e.g., NOx, SOx, PM2.5), improving air quality and public health."*	§4.5.1 – Environmental Impacts
Avoided Outages / Backup Power	*"DERs such as storage or microgrids that provide electricity during outages, enhancing reliability."*	*"DERs such as storage or microgrids can provide backup power and reduce outage frequency or duration."*	§4.5.3 – Reliability and Resilience
Avoided Utility Infrastructure Costs	*"The value of deferring or avoiding upgrades to transmission and distribution systems due to DERs."*	*"DERs can defer or eliminate the need for upgrades to transmission and distribution infrastructure by reducing peak loads or serving local demand."*	§4.2.3–4.2.4 – Avoided T&D Costs

WSAS Interim report benefit factor	WSAS Interim Report Definition/Description	NSPM Definition/ Description	Section in NSPM
Capacity Value (Generation, Transmission, Distribution)	*"The value of reduced need for generation, transmission, or distribution capacity due to DERs lowering peak demand."*	*"Avoided capacity costs reflect the reduced need for investments in generation, transmission, and distribution capacity due to DERs lowering peak demand."*	§4.2.2–4.2.4 – Avoided Capacity Costs
Customer Bill Savings	*"The reduction in electricity bills due to DERs through self-consumption, net metering, or other compensation mechanisms."*	*"DERs can reduce customer bills through lower energy consumption, demand charges, or participation in compensation mechanisms."*	§4.4.1 – Host Customer Bill Impacts
Economic Development / Job Creation	*"The stimulation of local economies through job creation, investment, and increased activity associated with DER deployment."*	*"DER deployment can stimulate local economies through job creation, investment, and increased economic activity."*	§4.5.2 – Economic Development
Equity and Access Benefits	*"Benefits that promote fair access to DERs and reduce energy burdens for historically underserved communities."*	*"DERs can promote equitable outcomes by improving access to clean energy, reducing energy burdens, and addressing historical disparities."*	§4.5.4 – Equity Impacts
Energy Generation Value	*"The value of energy produced by DERs, typically measured as the avoided cost of energy that would otherwise be purchased or generated*	*"Avoided energy costs represent the reduction in fuel and variable O&M costs associated with generating electricity, typically valued at the marginal cost of generation."*	§4.2.1 – Avoided Energy Costs
Fuel Diversity / Energy Security	*"The ability to maintain a stable and diverse energy supply, reducing dependence on centralized or imported fuels."*	*"DERs can enhance energy security by diversifying the energy mix and reducing reliance on centralized or imported fuels."*	§4.5.5 – Energy Security
GHG Emissions Reductions	*"The reduction in greenhouse gas emissions resulting from DERs displacing fossil-fuel generation."*	*"DERs can reduce greenhouse gas emissions by displacing fossil-fuel*	§4.5.1 – Environmental Impacts

WSAS Interim report benefit factor	WSAS Interim Report Definition/Description	NSPM Definition/ Description	Section in NSPM
		generation or improving system efficiency."	
Grid Services (e.g., voltage support, frequency regulation)	*"Services that support reliable operation of the grid, including voltage support, frequency regulation, and spinning reserves."*	*"DERs can provide ancillary services such as voltage control, frequency regulation, and spinning reserves, which support grid reliability and operations."*	§4.2.5 – Ancillary Services
Resilience and Reliability	*Reliability: "The ability of the electric system to deliver electricity in the quantity and quality demanded."* *Resilience: "The ability of the electric system to withstand and recover from disruptive events."*	*"DERs can improve reliability by reducing outages and enhance resilience by maintaining service during grid disturbances or extreme events."*	§4.5.3 – Reliability and Resilience
Temporal and Locational Value	*"The variation in DER value based on time of use (e.g., peak vs. off-peak) and location (e.g., constrained grid areas)."*	*"DERs provide value that varies by time (e.g., peak vs. off-peak) and location (e.g., constrained vs. unconstrained areas), which should be reflected in BCA."*	§5.2–5.3 – Temporal and Locational Impacts
Wholesale Market Price Suppression	*"The reduction in wholesale electricity prices due to DERs lowering demand or adding supply during peak periods."*	*"DERs can lower wholesale market prices by reducing demand or injecting supply during high-cost periods."*	§5.9 – Market Effects

Table C-2. Gaps Between WSAS Interim Report and NSPM Standards

Areas where the WSAS Interim report either omits key NSPM-defined benefit categories or lacks sufficient detail to meet NSPM's recommended evaluation standards include:

NSPM Category	Gap in WSAS Interim Report	Implication
DER Interaction Effects	No mention of how DERs interact with each other or with rate structures.	NSPM (§5.6) stresses the importance of modeling interactions to avoid double-counting or underestimating value.

NSPM Category	Gap in WSAS Interim Report	Implication
Fuel Price Risk Mitigation	Not addressed in WSAS Interim Report Table 4.	NSPM (§4.5.5) highlights this as a key benefit of DERs, especially for long-term planning.
Market Participation Revenues	Omits potential DER participation in wholesale or ancillary markets.	NSPM (§5.9) includes market revenues as a quantifiable benefit stream.
Non-Energy Impacts (NEIs)	Does not explicitly include NEIs such as appliance longevity, comfort, or noise reduction.	NSPM recommends including NEIs where relevant to customer experience and societal outcomes.
Program Administrative Costs	Focuses on benefits but does not address costs of DER program implementation.	NSPM requires both benefits and costs for a full BCA.

Table C-3. Uncertain Matches or Misalignments

The following WSAS Interim Report benefit factors partially align with NSPM definitions but lack clarity or specificity needed for rigorous BCA.

WSAS Interim Report Factor	WSAS Interim Report Definition	NSPM Reference	Uncertainty/Misalignment
Economic Development / Job Creation	"The stimulation of local economies through job creation, investment, and increased activity associated with DER deployment."	§4.5.2	WSAS Interim Report lists this as a benefit, but NSPM cautions that economic impacts must be net and not double-counted with other benefits.
Equity and Access Benefits	"Benefits that promote fair access to DERs and reduce energy burdens for historically underserved communities."	§4.5.4	WSAS Interim Report emphasizes equity, but NSPM requires clear metrics or valuation methods—Interim report does not specify how equity is quantified.
Resilience and Reliability	Reliability and resilience defined separately (see Section I)	§4.5.3	WSAS Interim Report combines these into one category, while NSPM distinguishes between

WSAS Interim Report Factor	WSAS Interim Report Definition	NSPM Reference	Uncertainty/Misalignment
			reliability (routine outages) and resilience (extreme events).
Temporal and Locational Value	"The variation in DER value based on time of use (e.g., peak vs. off-peak) and location (e.g., constrained grid areas)."	§5.2–5.3	WSAS Interim Report acknowledges these values but does not specify how they are calculated or integrated into compensation mechanisms.
Wholesale Market Price Suppression	"The reduction in wholesale electricity prices due to DERs lowering demand or adding supply during peak periods."	§5.9	WSAS Interim Report includes this, but NSPM notes that price suppression effects are complex and must be modeled carefully to avoid overstating benefits.

APPENDIX D: SUMMARY OF LITERATURE REVIEW OF DISTRIBUTED ENERGY RESOURCE (DER) COST-EFFECTIVENESS ASSESSMENT FRAMEWORKS

This appendix documents the cost-effectiveness tests and emerging valuation frameworks reviewed for the study. It is organized into two sections: (A) traditional, widely adopted cost-effectiveness tests, and (B) innovative or emerging tools that extend traditional frameworks to capture additional benefit and cost dimensions, particularly resilience and equity.

A. Traditional Cost-Effectiveness Tests

A.1 Utility Cost Test (Program Administrator Cost Test, PACT)

- Perspective: Utility system only (generation, transmission, distribution, and utility operations, regardless of ownership structure).
- Benefits assessed: Avoided utility system costs attributable to the DER— generation capacity, energy, ancillary services, and transmission/distribution capacity and losses.
- Costs assessed: Utility system costs incurred to implement the DER, such as point-of-interconnection equipment and controls/communications infrastructure.
- Methodology: Costs and benefits are expressed as annual utility revenue requirements; capital costs are amortized over the asset's regulatory book life, accounting for depreciation, taxes, debt, and equity.
- Limitations: Excludes participant and societal benefits/costs, which may understate broader program impacts; not well suited to programs whose costs fall mainly on customers or third parties.
- Jurisdictional use: Applied as a primary or secondary cost-effectiveness test in at least 13 states, including CA, CT, HI, MN, OR, TX, and VA.
- Key sources: E3 Avoided Cost Calculator for DERs; National Standard Practice Manual (National Energy Screening Project); NREL (2024).

A.2 Total Resource Cost (TRC) Test

- Perspective: Combined utility system and program participant.
- Benefits assessed: Avoided utility system costs, plus benefits experienced by participating customers, including non-energy impacts (particularly relevant for low-income programs).
- Costs assessed: All utility system and participant costs incurred to implement the DER.
- Methodology: Participant data (surveys, program evaluations, secondary data) is aggregated and combined with utility revenue-requirement calculations.
- Limitations: Often excludes non-energy benefits that can be important to program participation and market acceptance.
- Jurisdictional use: Used in 20 states, including CA, MA, NY, and IL.
- Key sources: National Standard Practice Manual; U.S. EPA, Understanding Cost-Effectiveness of Energy Efficiency Programs (2015 snapshot).

A.3 Societal Cost Test

- Perspective: Society as a whole — utility system, program participants, and broader societal impacts.
- Benefits assessed: Avoided utility system costs plus societal impacts such as environmental effects, economic development, public health, resilience, and energy security.
- Costs assessed: All utility system and non-utility system costs of the DER.
- Methodology: Sums utility and participant benefits/costs, then adjusts for additional societal costs; societal data may be drawn from other jurisdictions' studies.
- Limitations: Risk of double-counting or under-counting across societal, utility, and participant resilience benefits; comparable data may not be available for the jurisdiction of interest.
- Jurisdictional use: Used in 14 states, including AZ, CO, MN, OR, and WI.
- Key sources: National Standard Practice Manual; U.S. EPA (2015 snapshot).

A.4 Participant Cost Test (PCT)

- Perspective: Program participants only.
- Benefits assessed: Bill savings, incentives, and other benefits experienced by host customers.
- Costs assessed: All costs incurred by the host customer to install, operate, and maintain the DER.
- Methodology: Participant costs established through surveys, program evaluations, invoices, and adjusted market data.
- Limitations: Values avoided gas/electricity rates rather than avoided utility system costs, which runs counter to forward-looking, incremental analysis principles; does not address impacts on non-participants.
- Jurisdictional use: Used as a secondary test in AR, FL, GA, HI, IA, IN, MN, and VA, mainly to inform likely DER adoption and program design.
- Key sources: National Standard Practice Manual; U.S. EPA (2015 snapshot).

A.5 Rate Impact Measure (RIM) Test

- Perspective: Rate impacts on all customers.
- Benefits assessed: Avoided utility system costs attributable to the DER.
- Costs assessed: Utility system implementation costs plus lost revenues (equal to host customer bill savings).
- Methodology: Compares utility revenue requirements and rate impacts with and without the DER program; lost revenues estimated from reduced consumption, demand charges, or bill credits.
- Limitations: Does not measure net economic costs across the full customer population; does not account for participation rates, which limits its usefulness for distributional equity analysis on its own.
- Jurisdictional use: Used in 11 jurisdictions, including DC, FL, IA, and VA, largely to screen for rate impacts and flag where further equity analysis may be warranted.
- Key sources: National Standard Practice Manual; U.S. EPA (2015 snapshot).

B. Innovative and Emerging Assessment Tools

B.1 Social Burden Method

- Focus: Community-level resilience equity and wellbeing.
- Benefits/costs assessed: Non-economic and social burden costs of disrupted access to critical services (power, healthcare, food, communications) during and after outages.
- Methodology: Geospatial "effort-to-ability" ratio (SB = E/A), incorporating infrastructure accessibility, distance to service, and social vulnerability indicators; produces population-weighted burden indices.
- Limitations: Computationally intensive; requires high-resolution demographic and service-access data; effort/ability weighting introduces some subjectivity.
- Where used/piloted: New York, New Mexico, and Southern California; part of DOE/Sandia National Laboratories "Equitable Resilience Metrics" pilots. Developed by Sandia National Laboratories (SNL).
- Key source: "Integration of Equitable Resilience" (2024).

B.2 Power Outage Economics Tool (POET)

- Focus: Adaptive resilience and behavioral response to outages.
- Benefits/costs assessed: Economic losses from prolonged and adaptive outages, including dynamic value-of-lost-load (VOLL) as customers adopt coping strategies (relocation, backup generation, reduced consumption).
- Methodology: Survey-derived customer response data combined with behavioral economics and survival analysis/adaptive choice models, parameterized by outage duration, customer class, and demographics; produces marginal and cumulative cost curves.
- Limitations: Limited behavioral data for long-duration outages; adaptation functions rely on extrapolation.
- Where used/piloted: California, Illinois, and New York (2022–2024); supports DOE–LBNL Resilience Metrics and VOLL integration work, and ICE 2.0 extensions. Developed by Lawrence Berkeley National Laboratory (LBNL).
- Key source: "Power Outage Economics Tool" (2024).

B.3 Interruption Cost Estimator (ICE) 2.0

- Focus: Grid reliability and resilience valuation; baseline for equity-informed outage impact analysis.
- Benefits/costs assessed: Direct and indirect economic outage costs to residential, commercial, and industrial customers.
- Methodology: Monte Carlo simulation and regression models fitted to customer surveys and regional demographic/economic data; supports scenario modeling for reliability, resilience, and equity.
- Limitations: Focuses primarily on economic reliability losses; does not directly capture non-monetary or social resilience impacts without coupling to tools such as POET or the Social Burden Method.

- Where used/piloted: National scope; participating utilities include Puget Sound Energy, Portland General Electric, and ComEd (2023–2025); LBNL/DOE ICE 2.0 Phase I pilot. Developed by DOE, Brookhaven National Laboratory, and RI.
- Key source: icecalculator.com

B.4 Probabilistic Resilience Valuation

- Focus: Avoided economic loss, outage mitigation, and improved recovery.
- Benefits/costs assessed: Expected annual outage cost and avoided loss (via probabilistic risk assessment of hazards, likelihood, and vulnerability) against capital and operational costs of resilience investments (microgrids, grid hardening, backup systems).
- Methodology: Macro-econometric models, input-output models, and computable general equilibrium models.
- Limitations: Limited historical data for valuation, particularly for newer technologies/assets.
- Where used/piloted: New York — Consolidated Edison grid-hardening initiatives and the New York Prize microgrid competition.
- Key source: Ericson et al., 2023

B.5 Locational Net Benefit Analysis (LNBA)

- Focus: Transmission and distribution deferral value, reliability, and voltage support.
- Benefits/costs assessed: Avoided cost deferral value and system-level avoided costs against transmission capital and operating expenditures.
- Methodology: Determines the DER capabilities needed to achieve deferral, calculates associated avoided cost, and applies the LNBA heatmap methodology.
- Limitations: Highly location-specific; relies on publicly available indicative values and does not incorporate market-sensitive information.
- Where used/piloted: California — CPUC, PG&E, Southern California Edison, and San Diego Gas & Electric.
- Key source: LNBA Working Group Final Report on Demo B Filing (California Public Utilities Commission proceeding).

B.6 Grid-Interactive Efficient Building (GEB) Valuation

- Focus: Building-level energy, demand, and grid-value optimization.
- Benefits/costs assessed: Energy cost savings, demand charge reduction (peak shaving), demand response revenues, resilience and flexibility value, rebates/incentives, and societal grid value (T&D deferral, emissions reduction) — against upfront capital, baseline energy, and O&M/upgrade costs.
- Methodology: Portfolio Energy Optimization using DOE's EnergyPlus simulation engine; techno-economic analysis comparing first cost against NPV and payback period.
- Limitations: Findings are limited to prototype buildings; subject to modeling assumptions and cybersecurity considerations.
- Where used/piloted: National scope; GSA-owned buildings in Fresno, CA; New York, NY; Denver, CO; Atlanta, GA; Phoenix, AZ; and College Park, MD.

- Key source: "Value Potential for Grid-Interactive Efficient Buildings in the GSA Portfolio: A Cost-Benefit Analysis" (RMI).

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archived snapshot). https://19january2017snapshot.epa.gov/sites/production/files/2015-08/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf

APPENDIX E: COST SHIFT

The Contested Nature of Cost Shift

Cost shift is one of the most contested terms in distributed energy policy, and this report is transparent about the limits of what it can resolve. In utility regulation and energy policy, a cost shift occurs when one group of customers does not pay the full costs attributed to the electric system, and those costs are instead recovered from other customers through rates. With respect to rooftop solar, the term typically describes the claim that customers with solar reduce their electricity purchases and bills while continuing to rely on shared grid infrastructure; if the utility's fixed costs are not fully recovered from those customers, the unrecovered portion may be spread across non-solar customers.

The disagreement in practice is usually about whether a cost shift actually exists in a given policy context and, if so, how large it is, and the peer-reviewed literature reflects this same division. This appendix reviews that literature (both studies that document and quantify a cost shift, and studies that complicate or push back against that conclusion) before turning to the more limited body of Washington- and Pacific Northwest-specific academic research bearing on the debate.

Literature Documenting or Quantifying a Cost Shift

Several peer-reviewed studies document and quantify a cross-subsidy running from non-adopters to solar-adopting customers under net metering arrangements.

Borenstein (2017) uses residential data from Pacific Gas & Electric to show that solar adopters skew toward wealthier households, providing the empirical foundation for the regressivity concern that underlies much of the cost-shift debate.[224] Picciariello et al. (2015) directly quantify cross-subsidy flows from non-adopters to prosumers under various European distribution tariff structures.[225] Sergici, Yang, Castaner, and Faruqui (2019) present a method for quantifying the economic impact of net energy metering subsidies directly.[226] Formal welfare-economics treatments, including Alahmed and Tong's work in IEEE Transactions on Smart Grid, derive cross-subsidy magnitudes analytically from the structure of net-metering rate design itself.[227]

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[224] Borenstein, S. (2017). *Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives, and Rebates.* Journal of the Association of Environmental and Resource Economists, 4(S1), S85–S122. https://www.journals.uchicago.edu/doi/10.1086/691978

[225] Picciariello, et al. (2015). *Electricity distribution tariffs and distributed generation: Quantifying cross-subsidies from consumers to prosumers.* Utilities Policy, 37, 23–33. https://doi.org/10.1016/j.jup.2015.09.007

[226] Sergici et al. (2019) *Quantifying Net Energy Metering Subsidies*. The Electricity Journal, 32(8), 106632. https://doi.org/10.1016/j.tej.2019.106632

[227] A. S. Alahmed and L. Tong, (March 2023) *On Net Energy Metering X: Optimal Prosumer Decisions, Social Welfare, and Cross-Subsidies*. IEEE Transactions on Smart Grid, vol. 14, no. 2, pp. 1652-1663. https://ieeexplore.ieee.org/document/9733384

Literature Complicating or Challenging the Cost-Shift Narrative

Other peer-reviewed work complicates this picture or challenges it directly. Johnson, Beppler, Blackburn, Staver, Brown, and Matisoff (2017), using New Jersey solar data and PJM market and demand data, confirm that subsidization of solar adopters by non-participants occurs but find that the "utility death spiral" narrative is exaggerated, estimating only a 2% increase in non-participant bills even at significant levels of solar penetration.[228] A 2024 study in Solar Energy, using five-to-fifteen-minute interval data collected over one to three years from nine commercial-scale solar facilities in Virginia, finds that solar reduced monthly peak demand by an average of 22.9% and reduced demand during coincident peak periods for PJM utilities by an average of 42.3%, and argues on this basis that the premise that distributed solar burdens non-participants through cross-subsidization does not hold.[229]

Still other work locates the apparent subsidy in rate design choices distinct from net metering itself. Schwarz, Duma, and Camadan (2023) find that a meaningful share of the subsidy attributed to net metering is in fact driven by increasing-block-rate structures rather than by net metering as such, a finding directly relevant to this report's framing that cost shift is a property of mechanism design, and not an inherent feature of distributed solar and storage as a technology.[230] Relatedly, Darghouth, Barbose, and Wiser (2011) show that estimated bill savings and, by extension, estimated cost shift are highly sensitive to the specific rate design under which they are calculated, cautioning against treating "the cost shift" as a fixed, mechanism-independent quantity.[231]

Washington and Pacific Northwest-Specific Academic Literature

Washington-specific academic literature is considerably thinner than the national literature reviewed above, and no peer-reviewed study was identified that quantifies net energy metering cost shift using Washington utility data specifically. The closest such analysis, the Energy and Environmental Economics (E3) report on the benefits and costs of net energy metering in Washington, is a contracted policy study and is discussed elsewhere in this report.[232]

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[228] Johnson et al. (2017). *Peak Shifting and Cross-Class Subsidization: The Impacts of Solar PV on Changes in Electricity Costs*. Energy Policy, 106, 436–444. https://www.sciencedirect.com/science/article/abs/pii/S0301421517301787

[229] Eanes, A.M. & Smith, A.E. (2024). *Optimizing solar capacity for commercial-scale PV systems: An empirical cost-benefit framework for all stakeholders*. Solar Energy. https://www.sciencedirect.com/science/article/pii/S0038092X24000173

[230] Schwarz, P. M., Duma, N., & Camadan, E. (2023). Compensating Solar Prosumers Using Buy-All, Sell-All as an Alternative to Net Metering and Net Purchasing: Total Use, Rebound, and Cross Subsidization. The Energy Journal, 44(1). https://doi.org/10.5547/01956574.44.1.psch

[231] Darghouth, N. R., Barbose, G., & Wiser, R. (2011). The impact of rate design and net metering on the bill savings from distributed PV for residential customers in California. Energy Policy, 39(9), 5243–5253. https://www.sciencedirect.com/science/article/abs/pii/S0301421511004265?via%3Dihub

[232] Energy and Environmental Economics, Inc. (E3). (2023, December 21). Benefits and Costs of Net Energy Metering in Washington: Final Report. Prepared for a group of Washington electric utilities and the Washington Public Utility Districts Association (WPUDA). https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefits-and-Costs-of-Net-Energy-Metering-in-Washington_2023-12-21.pdf

The Washington-specific academic literature that does exist speaks instead to the adoption-pattern side of the debate, that is, to the empirical premise that gives the regressivity concern its force, rather than to the magnitude of the cost shift itself:

- Min, Lee, and Hurvitz (2023), a University of Washington College of Built Environments study focused specifically on Seattle, find that rooftop solar adoption is strongly tied to housing characteristics and concentrated in particular communities rather than distributed evenly across the ratepayer base — direct empirical support, localized to Washington, for the premise that solar adopters are not representative of non-adopting ratepayers.[233]
- Sifuentes, Major, McNett, Davis, and Nath (2024) model a hypothetical $100 million community solar investment in Washington State and find that equity-targeted allocation of that investment could generate $6.5–8.5 million in annual electricity bill savings for low-income communities. These results provide support for the broader argument that community solar and income-targeted deployment incentives can address the distributional concern that cost shift at its source, rather than solely through retail rate design.[234]
- Smith and Kirschen (2025) find that newer net-metering tariff designs, modeled using avoided-cost-based export pricing consistent with the direction of California's NEM 3.0, shift economic value away from solar-only adopters and toward customers who pair solar with storage.[235] This finding is directly relevant to this report's emphasis on storage attachment as a mechanism-design lever.

Limitations of This Review

Several limitations apply to the literature summarized above and should inform how it is used elsewhere in this report:

- No Washington-specific quantification of cost-shift magnitude exists in the peer-reviewed literature. The studies cited in the two preceeding sections draw on data from California, New Jersey, Virginia, and (for Picciariello et al.) European utilities, not from Washington's hydroelectric-dominated, cooperative- and public-utility-heavy generation and ownership landscape. Findings from these jurisdictions should not be assumed to transfer directly to Washington's rate structures, resource mix, or utility ownership patterns.
- The Smith and Kirschen (2025) case study uses California data, not Washington data. Although both authors are affiliated with the University of Washington, the paper's underlying case study is built on Fresno, California commercial load and generation profiles and California's NEM 3.0-style avoided-cost tariff structure. It is included here as directly on-topic, Pacific Northwest-authored academic work, not as an empirical study of Washington conditions.

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[233] Min, Y., Lee, H. W., & Hurvitz, P. M. (2023). Clean energy justice: Different adoption characteristics of underserved communities in rooftop solar and electric vehicle chargers in Seattle. Energy Research & Social Science, 96, 102931. https://doi.org/10.1016/j.erss.2022.102931

[234] Sifuentes, F. E., Major, S. C., McNett, B., Davis, R., & Nath, H. (2024). *Equity-driven investments in community energy systems: an optimization model applied to Washington State*. Environmental Research: Infrastructure and Sustainability, 4(4), 045007. https://doi.org/10.1088/2634-4505/ad951e

[235] Smith, L. D., & Kirschen, D. S. (2025). *Effects of Net Metering Policies on Distributed Energy Resource Valuation and Operation*. IEEE Power & Energy Society General Meeting (PESGM). https://arxiv.org/abs/2507.06595

- One additional item--a University of Washington working paper on rooftop and community solar adoption under income heterogeneity--was reviewed but excluded from this appendix. As of this writing it remains an arXiv preprint (arXiv:2408.11970) rather than a confirmed peer-reviewed journal publication, and it is not empirically Washington-specific.

Summary

Cost-shift analysis has itself evolved, from relatively narrow assessments of utility revenue recovery to multi-dimensional evaluations incorporating utility, ratepayer, participant, societal, environmental, equity, and resilience perspectives. This report acknowledges that debate; it does not resolve it. How large the shift is, and how to measure it, remains a contested empirical and methodological question that no single study — including those reviewed in this appendix — can settle for Washington specifically. What this report does instead is reframe the policy question in terms that Washington's statutory framework already answers: not whether cost shift exists, but how policy mechanisms can be designed to minimize it while still meeting the state's deployment and equity goals, as developed in Section V.

APPENDIX F: COMPARISONS BETWEEN WSAS PHASE 1 INTERIM REPORT AND 2023 WASHINGTON NET METERING REPORTS

Table F-1. Similarities of Benefits and Costs between the WSAS Phase 1 Interim Report and the Gridworks Technical Advisory Group to the Washington Utilities Net Energy Metering Evaluation

The WSAS Phase 1 report and the Gridworks report[236] cover similar benefits. Equivalent benefits, or areas where elements strongly overlap, are listed below.

WSAS Phase 1 Interim Report	Gridworks Report
Avoided generation capacity costs	Peak capacity – reduced peak capacity needs and deferral of new generation resources
Avoided energy costs	Avoided purchase of energy / Energy production from NEM solar systems
Avoided Environmental Compliance costs / RPS/CES compliance	Progress toward state/community clean energy goals (CETA)
Avoided T&D capacity costs	Deferred or avoided T&D investment
Avoided line losses (T&D)	Avoided T&D line losses
GHG Reduction	Avoided GHG emissions / Decreased thermal plant variable operating costs
Reduced utility bills (host customer)	NEM customer bill savings
Other Environmental (criteria pollutants)	Reduced criteria pollutants
Land Use	Reduced land impacts
Workforce development / Economic development	Local employment
Low income: Society	Equity – reduced energy burden for low-income customers
Reduced risk (fuel price)	Utility fuel price risk reduction
Resource diversity	Diversity of resources

[236] Gridworks. (2023). *Washington Net Energy Metering Technical Advisory Group: Final report* (pp. 15–16). https://gridworks.org/wp-content/uploads/2024/05/WA-NEM-TAG-corr.-Final-Report-12.22.2023-1.pdf

Table F-2. Similarities and Differences in Benefits Between WSAS and E3 Reports

The WSAS and E3 reports share many benefit categories, though several diverge. Table F-2 highlights these differences, showing where WSAS treats a benefit implicitly or through a related category while E3 names it explicitly (or vice versa).

Benefit Category	WSAS Phase 1 Interim Report	E3 Report
Hydroelectricity relief	Mentions "Reduction in ramping of hydroelectric dams" under the Societal section as a storage/solar +storage benefit, but it doesn't appear as a standalone generation or transmission benefit the way E3 frames it.	Lists this as a benefit (quantitative, ratepayer + societal), even though it ultimately found limited applicability in Washington due to winter peaking.
Secondary effect of increasing electrification in the home	Does not explicitly track this as a benefit category, though it's loosely implied in the host customer section	Includes this as a qualitative societal/ratepayer benefit
NEM customer hedge against fossil fuel volatility	Captures "Reduced risk" for the host customer but doesn't frame it specifically as a fossil fuel hedge the way E3 does.	Lists this as a qualitative NEM customer benefit
Federal funds as economic development engine	Does not have this as a discrete benefit (though it touches on economic development broadly)	Explicitly lists IRA tax credits and Local Solar for All as a societal/qualitative benefit.
Leverage private capital	Not present	Lists this as a qualitative societal benefit.
Investment in disadvantaged communities	Has "Low income: Society" which partially captures it, but E3's framing is broader (jobs + local spending in DACs, not just energy burden).	Lists this as qualitative/societal.

Table F-3. Additional Benefits Considered by WSAS

WSAS's Phase 1 framework includes several benefits that are not part of E3's benefit-cost results. These fall into two groups: benefits outside the scope of E3's analysis, and benefits that E3 discussed in Table 4 of its report but did not quantify. Tale F-3 organizes these benefits by tier to show where the two frameworks differ in scope.

Tier Category	Benefits	WSAS Report	E3 Report
Generation/ Ratepayer Tier	Avoided ancillary services costs	Tracks this for storage/solar +storage	Does not include
	Avoided Environmental Compliance costs	Tracks criteria pollution permit compliance specifically	Folds this into criteria pollutants more broadly
	Market price reductions	Included	Does not include
	Improved bulk system reliability / resilience	Tracks LOLE/EUE metrics	Does not include bulk system reliability as a distinct benefit
	Avoided Distribution O&M	Included	Does not list separately
	Avoided Distribution Voltage / Power Quality costs	Includes this as a non-wires alternative	Does not include it
	Improved Distribution system reliability and resilience	Tracks these as distinct storage/solar + storage benefits	Does not distinguish
Host Customer Tier	Increased asset value	Included	Does not include
	Improved productivity	Flags this (but hard to quantify)	Does not include
	Improved economic well-being (beyond bill savings)	Tracks self-curtailment, late payments, shutoff rates	Explores host customer economic wellbeing, but not in depth
	Increased empowerment / increased pride	Includes these as qualitative host customer benefits	Does not include
Societal Tier	Resilience (critical community)	Tracks this as a high-importance benefit for storage/solar + storage	Does not include community resilience as a distinct benefit (included in Table 4 as "declined")

Tier Category	Benefits	WSAS Report	E3 Report
	Water Use	Includes avoided water use from displaced thermal resources	Covers this as a qualitative societal benefit (reduced water consumption for fossil fuel cooling), not as a quantifiable line item
	Reduction in ramping of hydroelectric dams	Treats this as a distinct benefit with ecological and community implications	Absorbs hydropower into the general hydroelectricity relief category
	Local and State Tax Revenue	Tracks these as societal benefits	Does not include
	Energy Security (tracked via shutoff rates)	Includes this with a high equity relevance rating	Does not include energy security as a standalone benefit
	Public Health	Includes this as a medium-difficulty quantifiable benefit	Lists reduced criteria pollutants but doesn't separately name public health outcomes
	Reduced Credit and Collection Costs	Includes as a ratepayer/utility benefit	Does not include

Table F-4. Cost Comparison: Areas of Overlap between the WSAS Project and E3 Report

The E3 report (Table 2, p. 17)[237] identified five cost items and evaluated them all qualitatively. These included 1) Solar integration costs (Energy, Ratepayer + Societal), 2) Grid modernization / distribution infrastructure costs (Distribution Capacity, Ratepayer + Societal), 3) Utility program administration costs (Program Costs, Ratepayer + Societal), 4) Upfront system costs (N/A, NEM Customer, Quantitative), and 5) O&M costs (N/A, NEM Customer, Quantitative). This project also covers all five cost categories, although the authors phrase them differently.

E3 Cost Item	WSAS Report Equivalent
Solar integration costs	Increased Ancillary Services costs / Increased Energy Generation costs
Grid modernization / distribution infrastructure	Increased distribution capacity costs
Program administration	Program Administration
Upfront system costs (host customer)	(implied in O&M and Host Customer Risk)
O&M costs (host customer)	O&M costs (Host Customer)

Table F-5. Additional Costs Considered by WSAS Report

The WSAS project considered more cost categories than E3.

Cost Category	WSAS Interim Report	E3 Report
Mechanism Costs (E3 only captures program administration)	Rate Design cost shifting (Solar: High magnitude; Storage: Low)	Flags this as a concern in its narrative but doesn't list it as a formal cost line item
	Procurement contract costs	No equivalent
	Grid Services Compensation	No equivalent
	Incentives (Ratebase) — High magnitude in both solar and storage	No equivalent
	Incentives (Taxbase) — High magnitude in both	No equivalent

[237] Energy and Environmental Economics, Inc. (E3), *Benefits and Costs of Net Energy Metering in Washington* (Final Report, December 21, 2023), https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefits-and-Costs-of-Net-Energy-Metering-in-Washington_2023-12-21.pdf

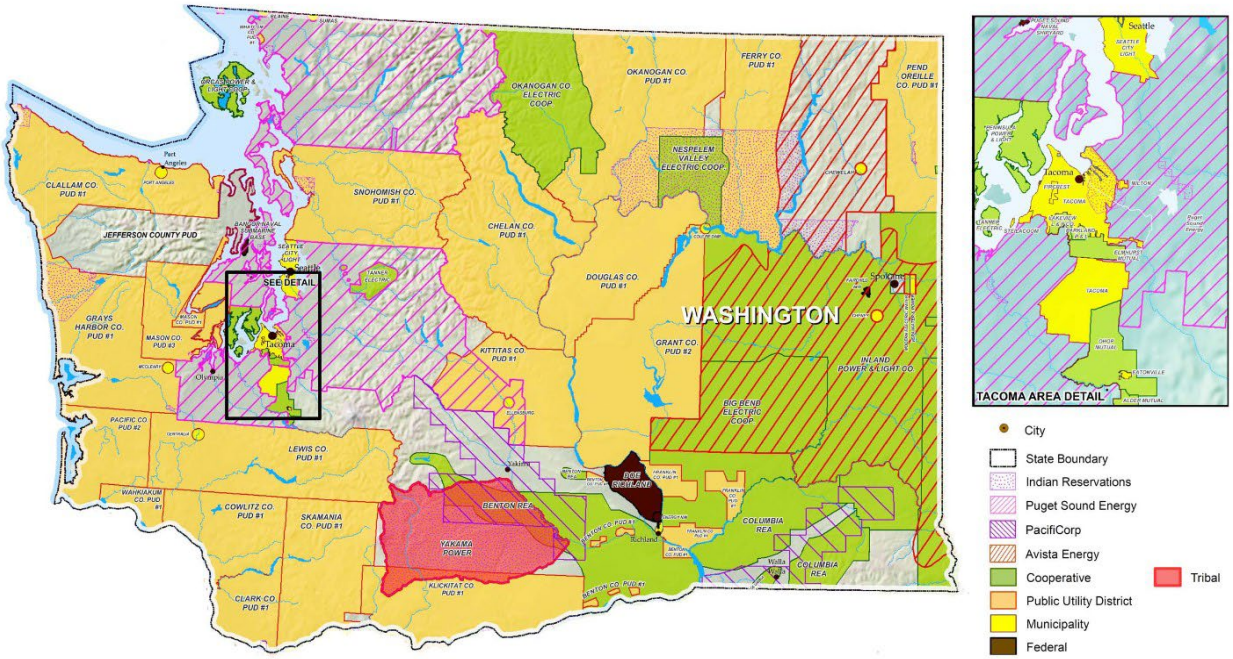
Cost Category	WSAS Interim Report	E3 Report
System Costs	Increased Energy Generation costs (Solar: n/a; Storage: Low)	No equivalent
	Increased Capacity Costs (Solar: Medium; Storage: Low)	No equivalent
	Market Prices Increase (Solar: n/a; Storage: Low)	No equivalent
	Increased Ancillary Services costs (Solar: High; Storage: Low)	No equivalent
Transmission Costs	Increased Transmission Capacity costs	No equivalent
	Increased Transmission System Losses	No equivalent
Distribution Costs (E3 only includes "Grid modernization")	Increased distribution capacity costs	No equivalent
	Increased Distribution System Losses	No equivalent
	Increased Distribution O&M	No equivalent
	Increased Distribution Voltage / Power Quality costs	No equivalent
	Reduced Distribution system reliability	No equivalent
	Reduced Distribution system Resilience	No equivalent
General Costs	Increased Credit and Collection costs	Not included
	Increased Risk	Not included
Other Fuels	Increased Fuel and O&M costs	No equivalent
	Increased Delivery Costs (incl. other fuel T&D)	No equivalent
	Increased Environmental Compliance	No equivalent
	Increased Market Price Effects	No equivalent
Host Customer Costs (E3 only has O&M and upfront system costs)	Increased Risk (Solar: Low; Storage: Medium)	No equivalent
	Health & Safety	No equivalent
Societal Costs	Increased GHGs (Solar: n/a; Storage: Low)	Not included

Cost Category	WSAS Interim Report	E3 Report
	Increased Other Environmental costs / Materials disposal (Solar and Storage: Medium)	Not included

APPENDIX G: WASHINGTON STATE ELECTRIC UTILITIES

Electricity service in Washington is provided by sixty-four utilities with varied governing and business structures. Washington is served by three investor-owned utilities whose terms and conditions of service, including NEM, are governed by the Washington Utilities and Transportation Commission. The majority of electric utilities in Washington state are public utility districts, consumer-owned (cooperatives, or co-ops) utilities governed by elected boards or city-owned utilities governed by city councils. Figure G-1 shows the distribution of utilities in the state.

Figure G-1. Map of Washington's Utilities[238]



[238] Solar Washington. (n.d.). Utilities in Washington. https://www.solarwa.org/utilities_washington_state

Table G-1. Washington Utilities: Number and Customers Served

Utility type	Number of utilities	Customers served	Share of customers*
Investor-owned utilities (IOUs)	3	~1,280,000	45%
Public utility districts (PUDs)	23 (of 28 PUDs total)	~831,660	29%
Municipal and local utilities	19	~587,674	21%
Rural cooperatives and mutuals	16	~142,433	5%
Total	**61**	**~2,841,767**	**100%**

** Share of customers is calculated from the customer counts above and rounded to the nearest percent.*

Publicly owned utilities (PUDs and municipal utilities) together serve ~50% of the state's customers, while cooperatives and mutual utilities serve an additional 5%.

Table G-2. Electric Utilities in Washington State[239]

PUD names are shown without "County PUD" for brevity.

Type	Count	Utilities
Investor-owned utilities	3	Avista Utilities, **PacifiCorp (Pacific Power), Puget Sound Energy**
Public utility districts (PUDs)	23	Benton, Chelan, Clallam, Clark, Cowlitz, Douglas, Ferry, **Franklin**, Grant, Grays Harbor, **Jefferson**, **Kittitas**, **Klickitat**, Lewis, Mason No. 1, Mason No. 3, **Okanogan**, Pacific, Pend Oreille, Skamania, Snohomish, Wahkiakum, Whatcom
Municipal and local utilities	22	***Cities:*** Blaine, Centralia, Cheney, Chewelah, Coulee Dam, **Ellensburg**, McCleary, Milton, Port Angeles, Richland, Sumas, Tacoma (Tacoma Public Utilities), Seattle City Light ***Towns:*** Eatonville, Ruston, **Steilacoom**, Yelm ***Other:*** Kalispel Tribal Utilities, Lakeview Light & Power, Modern Electric Water Company, Vera Water and Power, Yakama Power

[239] Northwest Clean Energy Atlas. (n.d.). *Northwest electric utilities overview.* https://www.nwceatlas.org/visualization/northwest-electric-utilities-overview

Type	Count	Utilities
Rural cooperatives and mutuals	16	**Benton REA**, Big Bend Electric Cooperative, Clearwater Power Co., Columbia REA, Elmhurst Mutual Power & Light, Inland Power & Light, Kootenai Electric Cooperative, Nespelem Valley Electric Cooperative, Northern Lights, Ohop Mutual Light Co., Okanogan County Electric Cooperative, **Orcas Power & Light**, Pacific County PUD No. 2, Parkland Light & Water, Peninsula Light Co., **Tanner Electric Cooperative**
Total	**64**	

APPENDIX H: THE NEED FOR FURTHER RESEARCH ON HYDROPOWER RAMPING

As wind and solar generation expand across the Pacific Northwest's grid, hydropower is increasingly used to "ramp," or rapidly adjust output up or down, to balance the intermittency of those resources. Hydropower is well suited to this role. In a 2017 PJM study,[240] it ranked as the generation resource with the greatest range of flexibility of any type on the system, ahead of natural gas.[241] DOE's HydroWIRES initiative has identified hydropower's flexibility as a significant source of low-carbon operating reserves. For integrating variable renewable energy nationally, hydropower's flexibility offers low-carbon operating reserves that can support approximately 140 GW of variable renewable energy (VRE), which is almost 10% of the VRE estimated to be necessary to achieve the (then) administration's goal of a net-zero carbon grid by 2035.[242] Today, data on the hydropower fleet is relatively fragmented, and hydropower capabilities are not always well represented in power system models.[243]

In the Columbia River Basin specifically, increased ramping carries direct ecological consequences that require further study. The Northwest Power and Conservation Council (NPCC) has found that ramping and flow fluctuation between hydro projects could increase significantly at certain times of the year, driven largely by growing use of the hydrosystem's flexibility to integrate renewable generation from renewable energy resources in the Northwest, and that this ramping and flow fluctuation can negatively affect fish.[244] The broader scientific literature on hydropower-related pulsed flows documents adverse effects on stream fish including stranding along changing channel margins, downstream displacement, and reduced spawning success from redd dewatering (water level drop leaving nests exposed) and disrupted migration timing.[245]

Researchers modeling hydropower's future role in higher-renewable grids with more wind and solar have identified this as an open question. A 2022 production cost modeling study found that optimized hydropower dispatch followed net load, compensating for solar and wind variability, and required larger swings in hourly output. The authors concluded that whether hydropower can actually operate this way needs further study, given competing water uses and ecological

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[240] PJM Interconnection is a regional transmission organization (RTO) that coordinates wholesale electricity across a much larger footprint than its name suggests–13 states plus the District of Columbia, stretching from Illinois and Michigan in the west to New Jersey in the east, and down through Virginia and North Carolina. It's the largest grid operator in North America by population served/market size.

[241] Energy Systems Integration Group. (n.d.). *Hydropower in a flexible grid*. https://www.esig.energy/hydropower-in-a-flexible-grid/

[242] National Renewable Energy Laboratory. (2023). *The role of hydropower flexibility in integrating variable renewable energy resources* (NREL/TP-86752). https://docs.nrel.gov/docs/fy23osti/86752.pdf

[243] Energy Systems Integration Group. (n.d.). Hydropower in a flexible grid. https://www.esig.energy/hydropower-in-a-flexible-grid/

[244] Northwest Power and Conservation Council. (2025, December 23). *Council approves draft Columbia Basin Fish and Wildlife Program for public review and comment*. https://www.nwcouncil.org/news/2025/12/23/council-approves-draft-columbia-basin-fish-wildlife-program-for-public-review-comment/

[245] Bozeman, et al. (2025). *The environmental impact of hydropower: a systematic review of the ecological effects of sub-daily flow variability on riverine fish*. Reviews in Fish Biology and Fisheries, 35(1), 45–76. https://doi.org/10.1007/s11160-024-09909-4

constraints, and that better understanding of these dynamics inform policies for both grid planning and reservoir release. [246] A companion analysis, produced in collaboration between national laboratories (NLR and Oak Ridge), examined how shifts in hydropower operations to balance wind and solar could modify effects on aquatic biota, underscoring that the ecological dimension of ramping is being treated as a distinct and ongoing research question rather than a settled one. [247]

For the Columbia River Basin, this research need intersects directly with existing salmon and steelhead recovery efforts. The Council's most recent draft Columbia River Basin Fish and Wildlife Program identifies reductions in ramping and daily flow fluctuations as one of its proposed actions the council says its proposed actions will result in cooler water temperatures, elevated spill levels in spring and summer, reductions in ramping and daily flow fluctuations and reduced predation, [248] and a 2026 literature review of hydropower and river restoration in the basin identifies measuring and modeling environmental and biological conditions at both small and large scales simultaneously as a key ongoing challenge, calling for continued research paired with closer coordination among researchers, regulators, and practitioners. [249]

Several concrete directions could help close these gaps. First, better empirical work is needed on how specific ramping-rate thresholds affect fish at different life stages: existing research suggests that even modest reductions in hourly discharge variation during critical reproductive periods can meaningfully increase offspring production, and that providing steadier low flows during periods of lower electricity demand may deliver ecological benefits at limited cost to hydropower operations– but this relationship has not been systematically quantified across species or basins. [250] Others suggested that providing more stable, low flows during a short time period when electricity demands are lower (weekends) could provide food web benefits while minimizing the economic costs to the hydropower facility. [251]

Second, researchers have proposed long-term monitoring programs that track the same physical and biological indicators across many sites and dam types. That approach would show which mitigation measures work and produce findings that apply beyond individual sites, which single studies cannot do. [252]

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[246] De Silva et al. (2022). *Hydropower operation in future power grid with various renewable power integration*. *Renewable Energy Focus, 43, 329-339.* https://doi.org/10.1016/j.ref.2022.11.001

[247] National Laboratory of the Rockies. (n.d.). *Grid integration with hydropower.* https://www.nlr.gov/water/grid-integration

[248] Northwest Power and Conservation Council. (2025, December 23). *Council approves draft Columbia Basin Fish and Wildlife Program for public review and comment.* https://www.nwcouncil.org/news/2025/12/23/council-approves-draft-columbia-basin-fish-wildlife-program-for-public-review-comment/

[249] Hester et al., (2026) *River Restoration in the Context of Hydropower Impacts to Anadromous Fish in Large River Networks: Evidence From the Columbia River Basin With Implications for Future Research.* https://onlinelibrary.wiley.com/doi/10.1002/rra.70111

[250] Gibeau, et al. *Run-of-river hydropower and salmonids: Potential effects and perspective on future research.* Canadian Journal of Fisheries and Aquatic Sciences. https://cdnsciencepub.com/doi/10.1139/cjfas-2016-0253

[251] ScienceDirect, (2022) *Bright spots for inland fish and fisheries to guide future hydropower development* https://www.sciencedirect.com/science/article/pii/S2772735122000051

[252] Nyqvist, D., Calles, O., Carlson, P., Holmgren, K., Malm-Renofalt, B., Widen, A. Bergengren, J., & Naslund, J. (2025). *Balancing hydropower production and ecology – ecological impacts, mitigation measures, and programmatic monitoring*. Knowledge and Management of Aquatic Ecosystems. 426:24. https://doi.org/10.1051/kmae/2025018

Third, most existing empirical research on flow-regulation effects on salmonids has focused overwhelmingly on a single species (brown trout accounted for more than 90 percent of empirical papers in one review) leaving a substantial gap in understanding how ramping affects the anadromous species most relevant to the Columbia Basin, including Chinook salmon, sockeye, and steelhead.[253]

Finally, continued investment in fish-tracking and passage-monitoring technology–such as miniaturized or self-powered tracking tags and improved biological design and evaluation tools for turbines–would give researchers more precise, real-time data on how individual fish respond to ramping events, complementing the population-level monitoring described above.[254] Pursued together, these directions–threshold-effect studies, standardized long-term monitoring, expanded species coverage, and improved tracking technology–would give Columbia Basin grid planners and fisheries managers a more complete evidence base for balancing renewable integration against ecological impact as hydropower ramping increases.

[253] Canadian Journal of Fisheries and Aquatic Sciences, *Run-of-River hydropower and salmonids: potential effects and perspective on future research* https://cdnsciencepub.com/doi/10.1139/cjfas-2016-0253
[254] DOE Water Power Technologies Office, *Monitoring Technology Development for Sensitive Species* (Hydropower Program Peer Review) https://www.energy.gov/sites/prod/files/2017/04/f34/monitoring-technology-development-sensitive-species.pdf

APPENDIX I: EXCLUDED FACTORS

This appendix documents the benefit and cost factors that were considered but not included in this second phase of the project. The research team began with the full range of factors identified in the literature and in statutory proceedings, listed in Appendix B, then narrowed that list to a representative list suited to Washington State's electricity system and energy policy goals. Exclusion does not mean a factor is not important or that it should be left out of future analyses. Several factors described here may warrant inclusion as Washington-specific data and methods develop.

Factors Excluded Due to Contested Pathways

Bulk system reliability and resilience and distribution system reliability and resilience were among the factors subject to the most discussion during the selection process and the most pointed methodological scrutiny. Both factors represent theoretically plausible benefits of distributed solar and storage deployment: a sufficiently large and geographically distributed fleet of storage-enabled resources could, in principle, contribute to bulk system reliability by providing reserve capacity and frequency response, and to distribution system resilience by enabling islanded operation during grid outages. However, the causal chain from any individual BTM installation to a measurable system-level reliability or resilience outcome is long and depends on assumptions about aggregation, dispatch coordination, and the counterfactual reliability performance of the system in the absence of distributed resources. Those are assumptions that are difficult to validate empirically at the scales of distributed deployment currently observed in Washington.

The distinction between host customer resilience (which was included in the representative set) and system-level reliability and resilience (which was not) reflects this causal clarity difference. The private resilience benefit to an individual customer who retains backup power during a grid outage is directly attributable to that customer's storage installation and can be quantified using established interruption cost methodologies. The system-level reliability benefit, such as the reduction in bulk system loss-of-load probability or distribution system average interruption duration attributable to a fleet of distributed resources, requires modeling assumptions and data that, in the current state of distributed energy resource deployment in Washington, would produce estimates of low reliability. These factors remain on the full list for incorporation into future analyses as the distributed resource fleet grows and as system-level dispatch data accumulates.

Factors Excluded Due to Scope Considerations

Economic and workforce development factors, including local job creation, regional economic output, and tax revenue effects, were assessed as falling at the boundary of the analytical scope appropriate for utility regulatory proceedings. While these impacts are real and represent genuine societal value attributable to distributed solar and storage deployment, their quantification typically relies on input-output economic modeling that is methodologically distinct from the utility-sector avoided-cost analysis that governs most distributed energy resource valuation. It was noted that economic development benefits are not conventionally included in the benefit-cost tests used in utility regulatory proceedings, including the National Standard Practice Manual tests,

and that their inclusion in a regulatory cost-effectiveness analysis could be contested on scope grounds.

Instead, the decision was to include job creation and economic development in the representative set at the level of methodological description only by documenting how other jurisdictions have approached its quantification and what values have been produced and without relying on Washington-specific estimates derived from input-output modeling. This approach acknowledges the factor's relevance to the broader policy conversation while maintaining analytical conservatism about its role in formal cost-effectiveness determinations.

Factors Excluded Due to Limited Washington-Specific Magnitude

Several factors in the full list were assessed as having limited magnitude in the Washington context relative to the analytical investment required to quantify them. Avoided ancillary services costs (the value of frequency regulation, spinning reserve, and voltage support potentially provided by distributed storage) is an example. While distributed storage can technically provide ancillary services in jurisdictions with the metering, communication, and market infrastructure to enable and compensate such services, Washington's current regulatory and market environment does not include a well-developed pathway through which BTM storage resources can access ancillary services compensation at scale. The potential magnitude of this benefit in Washington's near-term policy environment was therefore assessed as insufficient to justify its inclusion in the representative set, though it warrants attention as the regulatory infrastructure for distributed energy resource market participation evolves.

Avoided generation operations and maintenance costs, avoided fuel hedging costs, and resource diversity value were similarly assessed as lower-magnitude factors in the Washington context, and not because they are analytically unimportant in general, but because Washington's heavy reliance on hydroelectric generation (which has negligible fuel costs and relatively low operational variability costs) reduces the magnitude of these avoided-cost categories relative to their values in states with higher proportions of thermal generation. The cross-reference with the NSPM and E3 analyses confirmed that these factors are regularly included in distributed energy resource valuations elsewhere but carry less weight in the Washington-specific context.

Transmission Factors

Avoided transmission capacity costs and avoided transmission line losses were assessed as high-tractability factors with established quantification methodologies but were not included as standalone factors in the studied representative set. This decision reflected a scope judgment rather than an assessment of their magnitude or analytical importance: both factors are methodologically well-understood and are incorporated within the avoided energy cost and avoided bulk capacity cost analyses that are included in the representative set. Treating them as separate factors would have added analytical coverage without adding methodological breadth to the representative set. Future analyses that seek to produce comprehensive benefit estimates for specific Washington utility service territories should incorporate these factors explicitly.

APPENDIX J: PROJECT TEAM BIOGRAPHICAL INFORMATION

Oversight Committee

ANJAN BOSE, Regents Professor, School of Electrical Engineering and Computer Science, Washington State University; Site Director, Power System Engineering Research Center

Dr. Anjan Bose has over forty years of experience in industry and academia, as an engineer, educator, and administrator. He is well known as a technical leader in the power grid control industry, a researcher in electric power engineering, an educator in engineering, and an administrator in higher education. He is a Regents Professor at Washington State University (WSU), where he also served as the Dean of Engineering and Architecture (1998-2005) and in 2012-13 served as a Senior Advisor to the US Department of Energy (DOE) in the Obama administration. Dr. Bose is a Member of the US National Academy of Engineering (2003) and has served on many National Academy Committees. He is a founding Member of the Washington State Academy of Sciences and served as its President. He is also a Foreign Fellow of the Indian National Academy of Engineering. He is a Fellow of the IEEE and is active in several international professional societies. He was the recipient of the Outstanding Power Engineering Educator Award (1994), the Third Millennium Medal (2000) and the Herman Halperin Electric Transmission & Distribution Award (2006), from the IEEE. He has been recognized as a distinguished alumnus of the Indian Institute of Technology, Kharagpur (2005) and the College of Engineering at Iowa State University (1993).

DANIEL KIRSCHEN, Donald W. and Ruth Mary Close Professor, University of Washington

Daniel Kirschen joined the University of Washington in 2011 as a Close Professor of Electrical Engineering after spending 16 years at the University of Manchester (previously UMIST) where he was head of the Electrical Energy and Power Systems research group. He is a member of the Renewable Energy Analysis Lab, which focuses on how to build a smart grid that will maximize the amount of energy produced from renewable energy sources at a reasonable cost while maintaining the reliability of the electricity supply at the level to which we have grown accustomed. The main objective of his research focuses on developing techniques that achieve the optimal balance between providing a reliable grid service, minimizing the cost of providing energy, and reducing the environmental impact of the electrical system while facilitating the use of renewable energy sources. Before becoming an academic, Kirschen worked for Control Data and Siemens on the development of advanced application software for electric utility control centers. He is the author or co-author of two books and over two hundred scientific papers.

ELENA KRIEGER*,* Senior Director of Research and Policy, Just Solutions

Elena Krieger, PhD, is the Senior Director of Research and Policy at Just Solutions, a national nonprofit organization focused on developing equitable energy and climate solutions. Previously, she served as director of research at an interdisciplinary energy science and policy research institute, where she explored strategies to integrate public health, equity, affordability, resilience, and other societal benefits into energy transitions.

She is a member of the second cohort of New Voices at the National Academies of Sciences, Engineering, and Medicine, a member of the Disadvantaged Communities Advisory Group to the California Energy Commission and California Public Utilities Commission, and a member of the board of directors for the Center for Economic and Environmental Partnership. She has served on multiple committees for the National Academies, including the Committee on the Role of Net Metering in the Evolving Electricity System. Elena received her BA in Physics and Astronomy & Astrophysics from Harvard and her PhD in Mechanical and Aerospace Engineering from Princeton, where her research focused on optimizing energy storage for renewable energy systems.

H. ALAN LOVE*,* Professor, School of Economic Sciences; and Director, Center for Institutional Research Computing, Washington State University, Pullman

Dr. Love is a Professor in the School of Economic Sciences (SES), where he served as Director between 2011 and 2019. Currently, he also serves as the Director of the Center for Institutional Research Computing (CIRC) that provides high-performance computing (HPC) resources and expertise to advance computational and data-intensive research across WSU. Dr. Love holds a doctorate in Agricultural and Resource Economics from the University of California, Berkeley. Prior to joining Washington State University, Dr. Love was a Professor in the Department of Information and Operations Management and in the Department of Agricultural Economics at Texas A&M University, College Station. His research fields include industrial organization, information economics, supply-chains, and applied econometrics. His current research focuses on electricity markets with particular interest in smart grid edge designs to enhance prosumer response for increased resilience and decarbonization of electric power services. Dr. Love's research awards include the Quality of Research Discovery Award from the Agricultural and Applied Economics Association, Outstanding Published Research Award from the Western Agricultural Economics Association, and Article of the Year Award from the Northeastern Agricultural and Resource Economics Association.

AUTUMN PROUDLOVE, Managing Director – Policy & Markets, North Carolina Clean Energy Technology Center

Autumn Proudlove is the Managing Director - Policy & Markets at NCCETC, where she leads the Center's energy policy team and provides strategic direction on policy and market issues across the Center. Autumn oversees the policy team's portfolio of activities and directly manages its client-focused research services and publications, including the 50 States of Solar, 50 States of Grid Modernization, 50 States of Electric Vehicles, and 50 States of Power Decarbonization quarterly policy tracking reports. She is a co-principal investigator for the Carolinas Renewable Energy Development Assistance and Siting Hub project and oversees the Database of State Incentives for Renewables and Efficiency (DSIRE). Autumn is on the leadership committee for North Carolina's Solar for All program and serves on the technical steering committee for the National Open Data for Electrification (NODE) Collective. Autumn previously served on the National Academies of Sciences, Engineering, and Medicine's committee on the role of net metering in the evolving electricity system. Autumn received her Master's degree in Energy Regulation and Law, summa cum laude, from Vermont Law School and her Bachelor's degree in Environmental Studies, with a minor in Economics, from Dartmouth College.

NOEL SCHULZ, Inaugural Director, Institute for Northwest Energy Futures

Noel N. Schulz is Washington State University's former First Lady and the inaugural director for the Institute for Northwest Energy Futures. Dr. Schulz has more than 26 years of teaching experience at 6 U.S. universities including WSU. She has taught courses in power systems, energy conversion, application of computer programs to power engineering, application of intelligent systems to engineering problems, fundamentals of electrical circuits, renewable and distributed generation, and smart grid technologies. Dr. Schulz's research has focused on power systems modeling and analysis, smart grid applications, microgrids, renewable energy, and shipboard power systems. The research has been funded by multiple national agencies—including the National Science Foundation and the U.S. Departments of Defense, Energy, and Homeland Security—and private power equipment companies. She has published 175 papers and two book chapters. Prior to arriving at the University with her husband, WSU then-President Kirk Schulz, in mid-June 2016, she served as First Lady and associate dean for research and graduate programs in the College of Engineering at Kansas State University. She also directed the KSU Engineering Experimental Station and the Electrical Power Affiliates Program and was the Paslay Professor of Electrical and Computer Engineering. Dr. Schulz is the recipient of the 2016 Institute of Electrical and Electronics Engineers (IEEE) Fellow, the 2014 IEEE Education Society Hewlett-Packard Harriet B. Rigas Award for outstanding contributions in advancing recruitment and retention of women in IEEE and the engineering professions, and the 2014 American Society for Engineering Education (ASEE) Fellow.

DAN SCHWARTZ*,* Director, Clean Energy Institute; and Boeing-Sutter Professor of Chemical Engineering, University of Washington

Schwartz is the founding director of the UW Clean Energy Institute (CEI) and the Boeing-Sutter Professor of Chemical Engineering. His research explores transport and reaction in electrochemical systems, including the performance of complex electrodes used in energy storage and conversion. Schwartz served on the Technical Advisory Board for Washington's Energy Strategy in 2012 and, in 2018, he received the Presidential Award for Excellence in Science, Mathematics and Engineering Mentoring from the White House Office of Science and Technology Policy and the National Science Foundation. He is a Fellow of the Electrochemical Society and is a board and executive committee member of the Washington CleanTech Alliance.

SUSAN TIERNEY, Senior Advisor, Analysis Group

Dr. Tierney is an expert on energy policy and economics, specializing in the electric and gas industries. She has consulted to companies, governments, nonprofits, and other organizations on energy markets, as well as economic and environmental regulation and strategy. Her expert witness and business consulting services have involved industry restructuring, market analyses, utility ratemaking and regulatory policy, clean energy regulatory policy, transmission issues, wholesale and retail market design, and resource planning and procurement. Dr. Tierney is a former assistant secretary for policy at the US Department of Energy, state cabinet officer for environmental affairs, and state public utility commissioner. She chairs the board of directors of Resources for the Future; chairs the National Academies' Board on Energy and Environmental Systems; serves on the external advisory board of the National Renewable Energy Laboratory; and is a member of the boards of directors of the Alfred P. Sloan Foundation, the Barr Foundation, and other organizations. She has published widely, frequently speaks at industry conferences, and has lectured at many leading universities.

JONATHAN YODER, Distinguished Professor for Sustainable Development; and Director, State of Washington Water Research Center, Washington State University

Jonathan Yoder is the Director of the State of Washington Water Research Center and Distinguished Professor for Sustainable Development in the WSU School of Economic Sciences at WSU Pullman. His research specializations include natural resource and environmental economics, focusing on policy design and impact analysis, law, and contracts. Dr. Yoder joined the Water Research Center in 2014, but has been involved in water-related economic research for about 15 years. He has contributed to research on water pricing, economic analysis of water law, water markets, economic aspects of large environmental systems modeling efforts, benefit-cost analysis of water projects and water recreation, water quality impacts of livestock waste, and more. He has a BA in Biology, an MS in Applied Economics, and a PhD in Economics. Dr. Yoder has been President of the Universities Council on Water Resources, is a Member of the Board of Directors of the National Institutes of Water Resources, is a member of the Washington State Academy of Sciences, and has served in numerous other editorial and service positions.

Research Team

DONNA GERARDI, Senior Project Director

Donna Gerardi has worked in science policy for nearly 40 years. She was Executive Director of the Washington State Academy of Sciences, and she also held positions at the California Council on Science & Technology (CCST) and the U.S. National Academy of Sciences. Gerardi is currently Director of Research Engagement and External Partnerships at WSU. She works on research partnerships with industry, federal agencies, and federally funded R&D centers, and she is WSU's liaison to national research labs, including Pacific Northwest National Laboratory (PNNL). She also oversees joint projects, workshops, and formal agreements with these partners.

TED KO, Founder, Executive Director, Energy Policy Design Institute (EPDI)

Ted Ko works on energy policy, with a focus on distributed energy resources. He has testified on their role in an equitable, resilient energy system before the Federal Energy Regulatory Commission, the U.S. Congress, and more than a dozen states. As head of policy and government affairs at the energy storage company Stem, he worked on North American storage policy covering deployment targets, incentives, interconnection, and aggregation, and he wrote Stem's "Clean Resilience Roadmap," a framework for utility commissions planning resilient grids. He also co-founded the nonprofit Clean Coalition, where he worked on bills and regulatory decisions related to distributed energy. Before working in energy, he spent more than a decade as a software engineer and product manager at Yahoo! and other internet companies.

NICHOLAS MONTONI, Senior Program Director, North Carolina Clean Energy Technology Center

Nicholas Montoni brings over a decade of experience in federal, legislative, nonprofit, state, national laboratory, and academic clean energy policy and science. They currently serve as Senior Program Director - Policy and Markets at the NC Clean Energy Technology Center. They were formerly Deputy/Acting Chief of Staff at the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), providing strategic advice and ensuring efficient execution of

agency and leadership priorities. Nick previously worked on the House Energy and Water Development Appropriations Subcommittee, handling DOE's science and innovation accounts totaling more than $15 billion. Nick also previously worked for Congressman David Price of North Carolina, working on legislation to protect science and scientists at the Environmental Protection Agency and mitigate the environmental impacts of agricultural waste. Nick has also worked as a policy advisor for Third Way's Climate and Energy Program, Pacific Northwest National Laboratory, and the Washington State Academy of Sciences. Nick has a Ph.D. in physical chemistry from the University of Washington in Seattle, Washington, with a concentration in data science and machine learning.

DAN MULLEN, Editor and Consultant

Dan Mullen has worked in climate and energy for more than 20 years, in private and nonprofit roles covering policy, marketing and communications, program management, and business development. As an independent consultant, he provides editorial and advisory services to research institutions, cleantech companies, consultancies, and nonprofits working on the energy transition. He has written bylined and ghostwritten pieces for Science and Utility Dive, industry reports and white papers, and legislative and regulatory testimony. He has also edited research published by the U.S. Department of Energy and Nature Energy. He holds a B.A. in political science from Stanford University.

PATRICK MURPHY, PhD, Senior Scientist, PSE Healthy Energy

Dr. Murphy has more than 20 years of experience as an energy and systems engineer, operations research analyst, research program manager, and military intelligence officer. His work has covered energy access, emissions reduction, and security technologies, including research on resilient energy systems and the economics of reliability in the United States and Africa. At the Homeland Security Advanced Research Projects Agency (HSARPA), he managed research on resilient power systems to prevent and reduce outages caused by natural and human-made disasters. He has also consulted for government and defense agencies on research portfolios for future military systems, and he has helped researchers seek funding from public agencies and other partners. Earlier in his career, he served as an Army intelligence officer in the former Yugoslavia. Across these roles he has worked with teams from nonprofits, academia, government, and industry.

JULIE PADOWSKI, PhD, Research Associate Professor, School of the Environment, Washington State University

Julie Padowski earned her M.S. and Ph.D. degrees from the Soil and Water Science Department at the University of Florida, and was a post-doctoral research fellow at Stanford University with the Woods Institute for the Environment. As a research professor, her work encompasses a variety of issues related to natural resources management including water demand planning and forecasting, wildfire impacts on drinking water system resiliency, urban adaptations to water scarcity, and the food-energy-water nexus.

EMMA ROGERS, Implementation Coordinator, Washington State Academy of Sciences

Emma Rogers studied at Occidental College in Los Angeles, California, with a focus on Urban and Environmental Policy with an emphasis in Data Science and Public Health. Her research focused on California's climate policy with an investigation into the efficacy of strategies used to respond to climate change while advancing environmental justice. She brings organizational and analytics skills derived from experience with grassroots organizations, political campaigns and a policy focused non-profit, among others.

The research team gratefully acknowledges the contributions of the University of Washington Clean Energy Scholars (2025–2026) to this report. Their names can be found here.

Communications Team

BART SANBORN is a graphic designer and photographer based in Spokane and runs Sanborn Creative. His work focuses on brand identity, icon design, illustration, and photography, and he previously worked as a graphic designer at Itron. He has more than a decade of experience as a freelance designer, art director, and photographer, working in both print and web design.

TIMOTHY WOLF runs Wolf Narrative, a storytelling and content marketing consultancy for organizations working on the energy transition. He started his career as a newspaper reporter before moving into marketing, public relations, and communications in the energy technology sector. Over the past 25 years he has worked with organizations including Itron, SAIC/Leidos, Pacific Northwest National Laboratory, and AES Clean Energy on stories, thought leadership, and marketing campaigns about grid modernization, clean energy development, and consumer engagement.

APPENDIX K: REFERENCES

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