Measuring the Locational Value of Avoided Costs on the Distribution Grid

September 2026

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Prepared for the Flex Coalition

In early February 2026, the Flex Coalition held a workshop with regulatory and industry stakeholders to discuss program design options for a model flexible demand program to support grid reliability and affordability. Participants identified that the valuation of locational distribution system benefits of distributed energy resources (DERs), or lack thereof, remains one of the biggest barriers to expanding flexible demand programs across the country. While multiple markets and frameworks exist for valuing electric generation capacity and system-wide avoided costs, very few programs have captured the distribution system benefits in their value stack, particularly at a location-specific level. These distribution system benefits may far exceed other benefits to the electric system in some cases, and programs that focus only on bulk generation capacity systemically undervalue demand flexibility.

States have adopted a variety of avoided cost calculators (ACC) and valuation of distributed energy resources (VDER) frameworks, but no single model has emerged as accurate, scalable, and repeatable.

The Changing Dynamics of Distribution Avoided Costs

To appropriately value distribution system benefits from flexible loads, distribution system planners must distinguish between the value of a DER downstream of a substation/circuit that is near capacity or a DER downstream of a substation/circuit with significant margins.[1] Distribution systems facing rapid load growth from data centers, electric vehicles, and heat pump deployments are experiencing a very different dynamic than has been the typical utility experience over the past two decades.

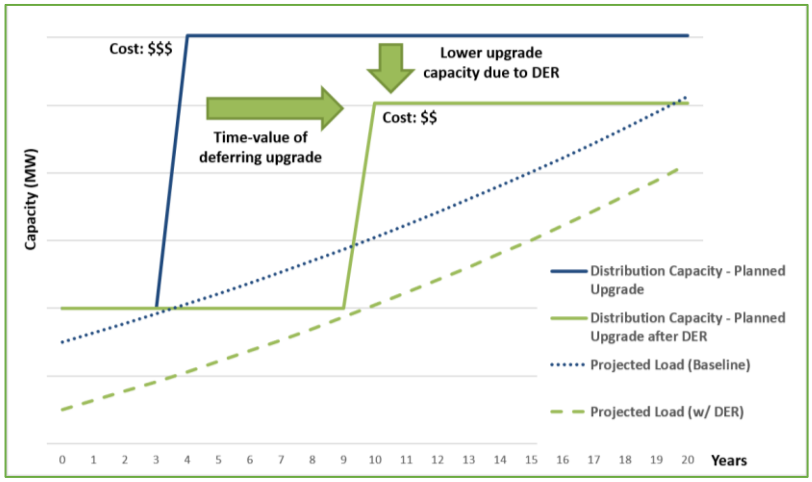
- **Flat Load Growth – The Legacy Scenario:** In a distribution system with significant margins and flat or declining loads, the value of avoided peak demand may well be close to zero – the system is already built, and reducing peak load doesn't materially change what will be built across the near- and medium-term time horizons. There is some benefit of marginal load reductions on the size and capacity of distribution system equipment in the future at time of replacement.
- **A Mix of Stressed Distribution Infrastructure – The Current System:** In a system where some substations and circuits have experienced increasing load but others remain underutilized, there may be alternatives for distribution system operators to shift load across circuits – these shifts are essentially free, improve the utilization of the existing system, and reduce the need for distribution upgrades. Nevertheless, there are limits to how much load can be shifted and where, and a meaningful number of substations and circuits may be truly constrained and require distribution upgrades – or flexible DER relief.

[1] For this paper, we use the term "circuit" to refer to a distribution circuit / distribution feeder, including all utility-owned equipment downstream of the electric distribution substation, generally including the lines, conductors, poles, transformers, and other equipment necessary to deliver power to the end customer at the desired voltage.

- **Load Growth Abounds – The Future:** The faster load is growing, and the more widespread the growth, the harder it becomes to shift load onto underutilized substations and circuits, and the greater the value of flexible DERs. In future scenarios with load growth across much of the distribution system, all at once, the value of avoided peak demand may be significantly higher than legacy or current evaluations.

The truth for any one utility lies somewhere between these scenarios – and may differ within the utility territory – but also relies upon uncertain predictions regarding where and how quickly load is growing.

Non-Wires Alternatives and Generic Avoided Costs Undervalue Flexible Demand



States and utilities have conducted a range of analyses of their distribution system, across either a subset of substations and circuits or the entire system, to identify distribution system values of DERs. The most typical example is a non-wires alternatives (NWA) analysis, where DERs are evaluated as a potential alternative to distribution infrastructure investment, typically within the 1-3 year planning horizons. Under these short planning horizons, a reasonable pace of DER deployment may be insufficient to fully offset a distribution infrastructure project. In these cases, the value attributed to DERs by the utilities may be zero; if the DERs cannot offset the full capacity requirement of the distribution system upgrade, it must still be built, and there are limited savings from avoided infrastructure.

Beyond specific, near-term, identified projects, energy efficiency and flexible demand resources can also avoid future distribution system infrastructure investments, even ones that have not yet been identified. Yet because these "unspecified"[2] benefits are harder to identify, they are often ignored in utility programs, attributing no credit to the cumulative long-term value of deploying DERs across specific priority areas or across the system in general. In some cases, states and utilities have identified methods for calculating both the near- and long-term values of these unspecified projects – yet current methods for doing so likely under-value DERs in the near-term, in some cases over-value DERs in the long-term, and do not align well with flexible demand technologies that do not have an easily defined measure life.

[2] The California Public Utilities Commission whitepaper on valuing transmission and distribution costs uses the term "unspecified deferral value" to refer to *"deferring the purchase and installation of generic infrastructure that has not been specifically identified by a utility or by the CAISO as needed for grid reliability resiliency, or safety, but is estimated to be needed. This value reflects the concept that not all grid needs can be anticipated with perfect foresight, and some portion of those unanticipated grid needs could be satisfied by DERs."* This unspecified value is a system-wide value and not locationally specific; the California definition, however, should not imply that all "unspecified" value must be system wide – as discussed below, calculating location-specific values based on unspecified future estimated upgrades can significantly improve valuation of DERs within distribution planning.

Current Practices for Locational and Systemwide Valuation

Location-Specific, Near-Term NWAs: Methodologies for evaluating location-specific, near-term distribution value on planned projects are well established – and often resource intensive. These methodologies require detailed utility planning and system design data, and need to be updated regularly to keep pace with changing load conditions. These are often conducted by outside consulting firms, rather than internal utility planners. Utilities vary in their experience in implementing specific NWA or analyses of alternatives – sometimes only doing so when required by their Public Utilities Commission – and these analyses are inherently limited in breadth and focused only on certain segments of the distribution system. Where location-specific modeling or NWAs have been completed, however, these values may provide the most accurate valuation, and these may be significantly higher than system averages.

System-wide Valuation: An alternative methodology aggregates locational values into a system-wide calculation. This creates an overall system-wide valuation that compensates all DERs equally, since the system-wide valuation is supposed to account for the diversity in locational valuations and the probability that a DER would be installed on a load-constrained circuit, now or in the future. As a result, however, these aggregated values do not fully reflect the additional value of installing DERs on a constrained circuit – just a statistical average of whether a randomly located DER may be installed in a constrained circuit. What they lack in specificity, they make up for in scale – allowing much wider deployment of incentives at a lower modeling and analysis burden.

- **Near-term:** The systemwide values generally derive from location-specific values conducted as part of distribution system planning or NWA analyses; the avoided cost values from those location-specific studies are then decremented to reflect the probability that a randomly installed DER will happen to be on one of the constrained circuits.
- **Long-term:** There is even greater uncertainty in how cumulative DER deployment may influence future grid planning; long-term avoided costs are typically estimated based on overall distribution system costs from general rate cases or FERC filings; these methods likely overstate the true marginal avoided cost of distribution upgrades, as they "can include cost categories that are not necessarily avoidable."[3]

Current Practices for Valuing Distribution System Avoided Costs

	Near-Term (1-4 years)	Medium-Term (5-9 years)	Long-Term (10+ years)
Location-Specific	NWA analysis of specific planned investments	Generally not assessed in granular distribution planning due to uncertainty	
System-wide	Reduce NWA location-specific value based on share of overall circuits/capacity	Average between near- and long-term	General rate case or FERC Form 1 filings $= \frac{Total\ Distribution\ Capital\ Spending\ (\$)}{Total\ Distribution\ System\ Capacity\ (kW)}$

[3] "2024 Distributed Energy Resources Avoided Cost Calculator Documentation, For the California Public Utilities Commission" EThree, October 2, 2024, p. 56

Due to the significant decrement to near-term calculations of system-wide values, near-term valuation has been significantly lower than long-term valuation. Examples from California and Illinois illustrate the significant disparity in near- vs. long-term values. Medium-term values are typically simply an average of the near- and long-term:

	California[4]			Illinois[5]	
Utility	**PG&E**	**SCE**	**SDG&E**	**ComEd**	**Ameren**
Near-term value ($/kW-year)	$1.54	$3.34	$2.38	$5.54	$9.43
Long-term value ($/kW-Year)	$57.29	$189.53	$89.51	$27.98	$34.30

These methods favor physical assets with a long lifecycle over flexible demand capabilities. DERs with a known, long lifespan may still be able to capture the future long-term value in a present-value analysis and reap the rewards, but demand flexibility is undervalued due to expectations of short-term duration and impacts of flexibility. If demand flexibility is viewed as a short-term asset, it can never bridge the gap to long-term benefits when using these legacy valuation methods. In real-world applications however, demand flexibility programs *can* accumulate capacity and grow to provide meaningful distribution relief, but only if they can be incentivized to appropriately reflect their potential over the medium- and long-term, not just the lower-value, limited potential over the next 1-4 years.

The Distribution Data Transparency Challenge

Appropriately valuing distribution system relief with high accuracy often requires significant amounts of data regarding the operational characteristics of the distribution system. Yet this complexity often leads to gross simplifying assumptions regarding distribution benefits of DERs, resulting in little or no value associated with distribution relief. Even in states where Distribution System Planning is conducted as part of a docketed proceeding, utilities may struggle to provide regulators, policymakers, and stakeholders with sufficient levels of detail to fully explore NWA and distribution system options beyond a few select projects. Even within a DSP proceeding, there is often insufficient detail to value and quantify the distribution system upgrades and costs. For example:

- FERC Form 1 filings include overall distribution system capital and annual expenses, but do not differentiate between capacity expansion (load driven), reliability, and other distribution system requirements (replacing legacy equipment, geographic coverage, etc.).
- Distribution system plans may identify specific constrained substation, circuits, or areas, but may not quantify the necessary upgrades in terms of potential avoided costs or capacity requirements. Identified load constraints are often not specific enough for DER aggregators and stakeholders to target installations to support load relief.
- NWA analyses or VPP programs for distribution relief tend to be small, targeted pilots, not the default assumption in system planning.

[4] Ibid, p 56.

[5] "The Value of, and Compensation for, Distributed Energy Resources in Illinois," EThree, January 2025, p. 27

Coordinated Distribution System Planning in Michigan Offers an Opportunity to Leverage DERs for Distribution Cost Relief

Michigan has many of the core structures in place to capitalize on DERs as a critical distribution grid resource – but doing so will require increased visibility into key distribution grid constraints across utilities, industry participants, and policymakers. The Michigan investor-owned utilities have filed five-year Distribution System Plans (DSP) on a rolling basis – starting with DTE Electric and Consumers Energy in 2017 and later expanding to include Indiana & Michigan Power, Upper Peninsula Power Company (UPPCO), Northern States Power Company – Wisconsin (NSP-W), and Alpena Power.[6] The Michigan Public Service Commission (MPSC), in coordination with the utilities and stakeholders, has made significant improvements to the planning process over the past nine years, and many of the necessary building blocks are already in place to fully inform locational distribution value analysis, but a few key data gaps remain. DTE's 2026 DSP identifies widespread locational value analysis as a current challenge, stating:

> *"Some detailed outputs, such as systematic locational value analysis, cannot be produced until foundational data and tools are in place. Today, estimating the value of individual projects is a manual, time-intensive effort applied mainly to projects exceeding certain funding thresholds. Ongoing investments will make this faster, more consistent, and more reliable, improving forecasting, modeling, scenario analysis, distribution planning, hosting capacity, interconnection screening and studies, and power-quality analysis, while enabling more granular evaluation of DER and NWA opportunities." (p. 98)*

These efforts are commendable and can form the critical foundation for robust locational value analysis. As these tools are fully developed, utilities can also take immediate steps to make existing data and processes more actionable, relevant, and useful for aggregators and other solutions providers working to support load flexibility in Michigan:

- DTE Electric's 2026 DSP identifies 27 potential candidates for NWAs – yet none of the candidate projects are selected to move forward as an NWA. DTE's criteria screen for only NWA projects where there is "no imminent solution needed" and the project can wait for three years or more; at the same time, they also screen for "no substantial load growth or reduction expected in the area." These criteria seem to eliminate precisely the types of projects that DERs are ideally suited to avoid – areas with significant load growth and where solutions are needed quickly – often quicker than capital infrastructure projects can support.[7] Reevaluating the screening criteria could expand opportunities for DERs to support circuits with significant load growth and where the value of load relief is the highest.
- DTE's DSP also makes it clear that a significant share of DTE's distribution infrastructure currently faces overload conditions: 20% of substations were over-firm in 2025, and that share could grow to 39% within the next 15 years under certain high electrification scenarios.[8] Yet there is no easy method for stakeholders to identify which circuits and substations are facing these conditions and constraints. The DSP identifies 12 near-term substation loading mitigation projects, but these

[6] Order dated September 8, 2022, Case U-20147

[7] DTE Electric 2026 DSP Plan Filing, April 28, 2026, Case U-22104

[8] Ibid,,Exhibit 2.6, p. 19.

represent less than 1.5% of total substations. This leaves approximately 18.5% of substations which are currently experiencing constraints, but are not identified in the DSP plan in a way that lets DERs provide targeted load relief.

- The Consumers Energy 2023 DSP identifies overall annual spending on overload mitigation, and states that there are thousands of components (cables, fuses, overhead lines, reclosers, regulators, switches, and isolators) loaded above 100% of their intended design value – yet it does not provide a breakdown of where these components are located or the overall capacity improvements from the intended upgrades, making it difficult for industry participants to capture value or work in support of relieving these constraints.[9]
- The Michigan IOUs also publish hosting capacity maps for DERs – another source to identify constrained circuits that could benefit from local load relief. Yet while the maps identify dozens of circuits that show no available capacity, these circuits are likely not constrained at all hours of the year, and flexible loads could likely help reduce constraints if more data and price signals were available to encourage such deployment.

The MPSC is taking the opportunity presented by DERs and VPPs seriously, and continues to work to improve the distribution planning processes to better support DER deployment as a core solution.[10] Notably, in the recent Consumers Energy rate case, the MPSC issues a "prospective warning" in support of VPP alternatives to capital expenditures, borrowing language from the Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (MEIU) to state that "*in light of the 'extensive support for VPPs' in the record and the fact that 'VPPs can provide a multitude of grid benefits, increase system reliability, and avoid or defer costly capital investments,' future proposed investments that fail to account for VPPs may be disallowed.*"[11]

Multiple complimentary efforts within Michigan also enhance the opportunity provided by locational value analysis. Michigan has partnered with the National Association of State Energy Officials as a key early stakeholder in the Open Benefit-Cost-Analysis (OpenBCA) project, which could leverage locational values as inputs across a range of cost effectiveness screening efforts. The Michigan's Department of Energy, Great Lakes, and the Environment (EGLE) also intends to deploy the measured-savings pathway under their Home Energy Rebate programs, and UPPCO has proposed a measured savings pilot within their Energy Waste Reduction program as well;[12] these measured savings programs allow for enhanced incentives based on time and location factors – further emphasizing the need for locational value analysis to help guide incentive program design.

Michigan has a growing array of programs that can support development and utilization of distribution system locational value, including strong MPSC support for flexible demand, iterative refinements in DSP planning processes over many cycles, expedited pilot authorities, ongoing capacity hosting efforts, and parallel programs to leverage location value input in measured savings and BCA practices. Stakeholders will need to collaborate across these efforts to maximize grid value of DERs for ratepayers.

[9] Consumers Energy DSP Plan Filing, September 27, 2023, Case U-20147

[10] In addition to leveraging VPPs for managing load growth, the MPSC and utilities are also balancing an gaining distribution system with significant non-load growth related reliability concerns.

[11] Order dated March 27, 2026, p. 493, Case U-21870

[12] Case No. U-21684

Moving Towards a Simplified Model for Location-Specific Valuation Over the Long-Term

Not all circuits were created equal. Using system-wide averages to reflect avoided costs inherently understates the value of DERs to some substations and circuits, and overstates it for others. To fully unlock flexible demand and DER capabilities to achieve consumer affordability and rate reductions, utilities must better reflect, publish, and incentivize DER deployment on currently- and soon-to-be-constrained distribution infrastructure. While such analysis inherently requires assumptions about future load growth, these are precisely the assumptions that are already considered in ongoing distribution system planning and integrated resource planning—and which increasingly need to be re-examined due to explosive load growth from data centers and electrification.

When possible, a location-specific or circuit-level analysis of every node on the distribution system – looking over medium and long-term horizons under varying load growth scenarios – provides the greatest fidelity and can identify opportunities for DER value beyond the traditional NWA. Where such detailed engineering and modeling analysis is not feasible, more simplified approaches can approximate the value of DERs using more limited data inputs, while still providing a level of locational granularity not captured in current distribution planning practices.

To support policymakers in exploring potential distribution system benefits of DERs, the Flex Coalition is releasing the accompany decision support tool to demonstrate a simplified methodology for calculating long-term distribution system value. Using just six inputs, the tool estimates the value of the avoided distribution costs for a given segment on the distribution system.[13] The required inputs include:

- The current design capacity/peak load of the segment;
- The current/recent peak load on the segment, as a percent of design capacity;[14]
- The projected rate of load growth for the segment;[15]
- The average cost of distribution system capacity upgrades, ideally derived from actual recent distribution capacity upgrade projects;
- The average service life of representative distribution system upgrades; and
- The utility weighted-average cost of capital (WACC).

The tool is intended to help policymakers in understanding the potential for location-specific distribution value for constrained, partially constrained, and unconstrained segments of the utility distribution grid. While this methodology does not replace detailed power system engineering analysis, it provides a greatly simplified approach that can support decision makers in evaluating flexible demand, energy efficiency, and other DER program location-specific benefits at a greater level of accuracy than systemwide averages typically used in current practice. The tool also quantifies the portion of the system value from the reduced capacity of the upgrade and from the time-value of delaying/deferring the upgrade, providing insights

[13] A segment could include an individual distribution feeder circuit, a substation and all of the downstream circuits combines, or some other collection of utility infrastructure subject to shared physical load constraints.
[14] As discussed above, distribution operators often have flexibility in shifting load across substations and circuits to avoid overload conditions; the estimated ability to shift loads should be included as a reduction in the current peak load of the distribution infrastructure to reflect these capabilities, where appropriate.
[15] Where there is significant uncertainty regarding the potential load growth, utilities and policymakers should evaluate multiple different load growth scenarios as a sensitivity analysis.

into the components of the valuation to inform decision-making. A more detailed explanation of the decision support tool is included in Appendix B.

Conclusion

Most current VPP and flexible load incentive programs primarily focus on capacity, resource adequacy, and wholesale energy costs, and to some extent, transmission – yet they all too often ignore the value to the distribution system. In some areas, the distribution value may represent more than half of all of the grid benefit of a VPP – presenting a significant opportunity to improve cost savings for ratepayers while also accelerating the deployment of DERs.

The methodologies and tools detailed in this paper identify opportunities for regulators, policymakers, utilities, and stakeholders to improve on the current status quo processes towards a more robust framework for valuing locational distribution system benefits, filling key gaps in current valuation of avoided distribution costs in calculating DER incentive payments. Some states and utilities have conducted significantly more rigorous analyses to estimated location-specific benefits – and we highly encourage such analyses when possible. The options in this paper are presented as a simplified process and a starting point for the analysis. They are estimates based on future scenarios with significant uncertainty. Yet we also know that DERs can and do provide value to the distribution system, and these estimates offer an alternative to systemwide values or, as is too often the case, no credited value at all.

These methods should be paired with significantly expanded rigor and transparency in distribution system analysis for potential load relief by DERs. Policymakers should ensure that marginal costs of distribution system upgrades are well quantified, published, and linked to incentive programs. While there are legitimate sensitivities for some elements of grid operations, overall system costs and infrastructure plans should be transparent to help drive DER investment where it is most needed.

Improving the transparency and valuation of locational distribution value will provide a critical incentive signal to DER owners and aggregators to drive deployment and flexible demand in the areas of the distribution system facing the greatest needs. These locational values can be incorporated into broader incentive and cost effectiveness frameworks – such as the Open Benefits Cost Analysis, various virtual power plant tariffs, or the forthcoming Flex Coalition’s Flexible Demand Framework.

Appendix A – Case Studies on State Value of DER Practices

New Hampshire - *Locational Value of Distributed Generation* (LVDG)

The *Locational Value of Distributed Generation* study, conducted by Guidehouse for the New Hampshire Public Utilities Commission in 2019, assessed the locational value of solar PV, batteries, and small hydro power over a 10-year time horizon across all three of New Hampshire's regulated electric distribution companies. The study:

- Examined utilities' 5-year historical spending reports, as well as their 10-year distribution system investment plans to identify capacity-constrained circuits.
- Reviewed 696 locations, identified 122 locations for further modeling, and performed deep-dive analysis on 16 locations. These locations were then assessed based on the value of different DER technologies under varying load-growth scenarios.
- Projected locational values up to 10 years in advance through the modeling scenarios.
- The study does not extrapolate from location-specific values to a broader system-wide value.
- Was intended to inform future system-wide calculations of the value of distributed energy resources, in addition to Least Cost Integrated Resource Plan dockets.
- Study cost: $400,000

Massachusetts - *DER-iving Local Value: Distribution Grid Services in the Commonwealth of Massachusetts*

The Distribution Grid Services in the Commonwealth of Massachusetts report, prepared by E3 for the Massachusetts Clean Energy Center and delivered in September 2025, assessed various frameworks to draw conclusions regarding the value of DERs to the distribution grid, but did not specifically establish avoided cost values. The study:

- Does not mention specific data sources, or differentiate between short-and-long term distribution system benefits.
- Focuses on the distribution value of DER solely from a locational lens for the purposes of developing a locational adder for DER.
- Provides a framework for assessing location-specific values and avoided costs, but does not actually perform the analysis for real-world Massachusetts utilities.
- Found that "Distribution Grid Services require location-specific mechanisms not available through current programs which focus on bulk system value."
- Supported execution of the Grid Services Compensation Fund to provide local capacity relief. This is intended to complement the system-wide Connected Solutions program.

Pennsylvania - *Avoided Cost of Transmission and Distribution Capacity Study*

The *Avoided Cost of Transmission and Distribution Capacity Study,* conducted by Demand Side Analytics for the Pennsylvania Public Utilities Commission and delivered in July 2024, provides the most comprehensive analysis of distribution-level avoided costs across all states.

- The analysis conducted 1,000 simulations of varying load-growth scenarios for each feeder and substation across all four investor-owned electric distribution companies in Pennsylvania. It also incorporated hourly SCADA system data for each feeder and substation where available.
- This study blends both location-specific and systemwide elements, but ultimately derives a systemwide value as a statistical average of the location specific values. This highly granular report could also support location-specific valuation of specific substations or circuits.
- Conducted calculations "for each feeder and substation, transformer, or terminal (depending on the EDC) that had a valid growth rate and operating limit. Next, the study team layered the two levels (feeder plus substation/transformer/terminal) to get the total distribution avoided cost for each site" (p. 38).
- This census of localized distribution values was then aggregated into a system-wide valuation which factored in "the likelihood that reductions would be in locations with or without value due to random chance" (p. 38).
- In additional to seasonal summer and winter peak annual avoided cost values, the study also generates hourly allocations of value for each utility (see examples below:

Table 8: Seasonal Allocation of Avoided Distribution Cost

EDC/Rate District	Summer Distribution ($2026/kW-year)	Winter Distribution ($2026/kW-year)
PECO	$39.61	$10.26
PPL	$25.11	$32.44
Duquesne	$59.28	$0.21
FE: Met-Ed	$52.46	$6.70
FE: Penelec	$37.18	$5.79
FE: Penn Power	$43.52	$16.27
FE: West Penn	$41.25	$5.05

Table 13: PECO Distribution Time Differentiated Value – 2026

Hour Ending (EPT)	Act 129 Peak Defintion	Summer Deferral Value ($/kW-year)	Winter Deferral Value ($/kW-year)
1	Neither	$0.57	$0.22
2	Neither	$0.52	$0.20
3	Neither	$0.48	$0.20
4	Neither	$0.45	$0.21
5	Neither	$0.44	$0.26
6	Neither	$0.46	$0.34
7	Neither	$0.51	$0.46
8	Winter Peak	$0.61	$0.55
9	Winter Peak	$0.77	$0.58
10	Neither	$1.02	$0.56
11	Neither	$1.44	$0.52
12	Neither	$2.07	$0.49
13	Neither	$2.76	$0.46
14	Neither	$3.37	$0.44
15	Summer Peak	$3.77	$0.40
16	Summer Peak	$4.11	$0.40
17	Summer Peak	$4.15	$0.46
18	Summer Peak	$3.67	$0.59
19	Winter Peak	$2.68	$0.62
20	Winter Peak	$1.99	$0.59
21	Neither	$1.52	$0.55
22	Neither	$1.03	$0.48
23	Neither	$0.70	$0.39
24	Neither	$0.53	$0.30
Seasonal Total ($2026)		$39.61	$10.26
Season Total Within Peak Definition ($2026)		$15.69	$2.34

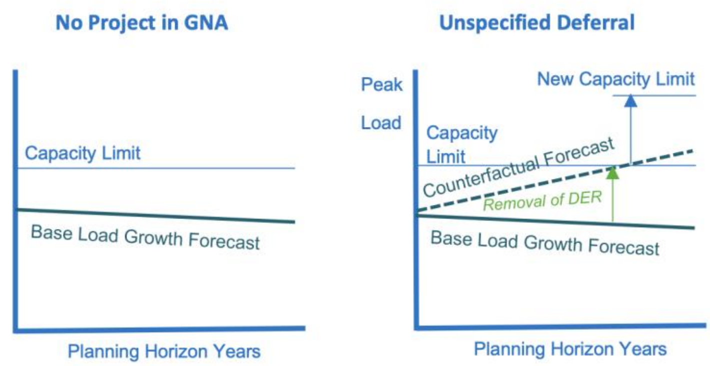
California Public utilities Commission (CPUC) Avoided Cost Calculator (ACC):

The CPUC ACC is often viewed as the gold standard of avoided cost methodology, and distinguishes between the near- and long-term system-wide distribution value of DER.

- Near-term forecasts use the utilities' Grid Needs Assessments (GNAs), which are annual filings that utilize a 5-year planning horizon. The ACC then estimates the counterfactual scenario of "no new DERs" installed to explore which circuits would have experienced capacity overloads were it not for the DERs installed. The ACC then estimates the percentage of distribution capacity overloads that lead to a deferred distribution upgrade – notably, a relatively small percentage. The CPUC whitepaper which provides the basis for the ACC process highlights that many projected overloads are solved via other load-shifting mechanisms, and in the CPUC example, only 23% of overloads result in distribution capacity upgrade investments. The ACC continues this process, using the ratio of overloads and upgrades from the Distribution Deferral Opportunities Report

(DDOR). Yet the DDOR suffers from the same near-term focus as other NWA analyses, and may discount the cumulative impact and potential of DER deployment beyond what can be achieved in the short term for project deferrals.

Figure 7-1. Project need from counterfactual forecast



- Long-term forecasts (Years 8-20) utilize data from utilities General Rate Cases (GRCs), which notably "are not location-specific and can include cost categories that are not necessarily avoidable" (p. 56). Years 6-7 are calculated as a linear transition between the near- and long-term forecasts.
- Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) provide two examples of how GRC data is incorporated into long-term avoided cost values.
  - SCE utilizes "a regression analysis of cumulative distribution capacity-related investments and cumulative peak loads, consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates" (p. 59). Subtransmission and distribution costs are then broken down across the substation and circuit level.
  - PG&E utilizes Peak Capacity Allocation Factors (PCAF), which are hourly allocation factors that measure coincident demand across primary capacity equipment, and Final Load Transformer (FLT) Loads, which provide a non-coincident measure of demand on secondary equipment. These then inform avoided cost calculations that are weighted by climate zone.

Table 7-3. Long-Term Distribution Capacity Costs for PG&E by Division (Base Year of 2021)

		[A]	[B]	[C]	[D]	[E]	[F]
Division	Climate Zone	Primary Projects Total $/PCAF-KW-YR	Secondary Distribution $/FLT-KW-YR	Total PCAF Loads PCAF kW	Total FLT Loads FLT kW	Secondary Cost [B*D/C] $/PCAF-KW-YR	Total Distribution Capacity Cost [A+E] $/PCAF-KW-YR
CENTRAL COAST	4	$42.51	$1.66	823,510	1,759,256	$3.54	$46.05
DE ANZA	4	$44.84	$2.20	741,675	1,234,311	$3.66	$48.51
DIABLO	12	$69.63	$2.68	1,265,169	1,524,487	$3.22	$72.85
EAST BAY	3A	$40.86	$1.84	627,862	1,338,170	$3.92	$44.78
FRESNO	13	$48.47	$2.01	2,164,629	3,575,125	$3.31	$51.78
HUMBOLDT	1	$43.54	$1.40	292,803	736,437	$3.53	$47.06
KERN	13	$51.00	$2.20	1,585,454	2,449,767	$3.40	$54.40
LOS PADRES	5	$63.38	$1.82	492,381	1,041,742	$3.85	$67.22
MISSION	3B	$43.83	$2.23	1,233,354	2,022,915	$3.65	$47.48
NORTH BAY	2	$52.95	$2.06	647,540	1,283,383	$4.08	$57.03
NORTH VALLEY	16	$63.36	$1.73	742,213	1,324,624	$3.08	$66.44
PENINSULA	3A	$48.18	$2.02	766,475	1,436,434	$3.78	$51.96
SACRAMENTO	11	$46.65	$2.23	970,943	1,589,591	$3.66	$50.30
SAN FRANCISCO	3A	$48.93	$2.36	829,544	1,435,075	$4.08	$53.01
SAN JOSE	4	$46.29	$2.45	1,369,868	2,130,431	$3.81	$50.10
SIERRA	11	$43.89	$1.88	1,187,910	1,833,534	$2.90	$46.79
SONOMA	2	$43.15	$1.84	544,454	1,147,401	$3.87	$47.01
STOCKTON	12	$44.06	$1.99	1,207,506	2,114,747	$3.48	$47.54
YOSEMITE	13	$67.14	$1.85	1,090,280	2,098,437	$3.56	$70.70

Columns A and B provided as updated values by PG&E for the 2022 ACC

Columns C and D from PG&E 2017 GRC Phase II to maintain same climate zone weighting as the 2021 ACC

As discussed above, the differing data sets for near-term and long-term avoided costs yield significantly different valuations over the time horizon:

Figure 7-2. Illustrative Distribution Avoided Cost Transition

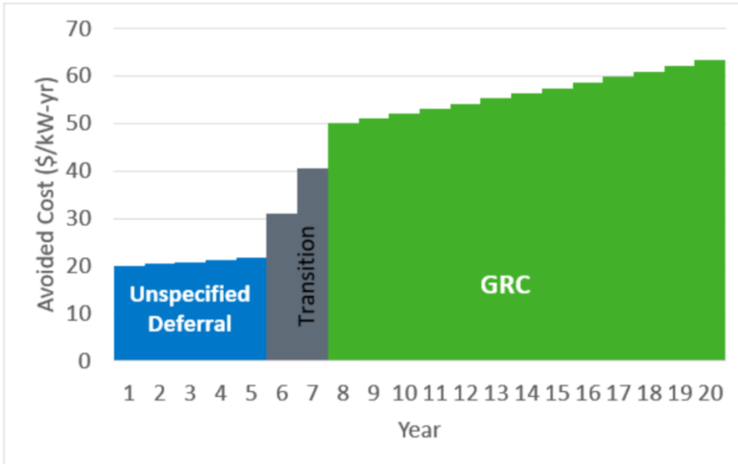


Table 7-1. Near-Term Distribution Marginal Costs

	PG&E	SCE	SDG&E
Circuits only		$0.97	
B-Bank Substations		$1.93	
A-Bank Substations		$0.26	
Subtransmission		$0.17	
Total Distribution Capacity ($/kW-yr.)	$1.54 ($2023)	$3.34 ($2023)	$2.38 ($2023)

Table 7-2. Long-term Distribution Marginal Costs

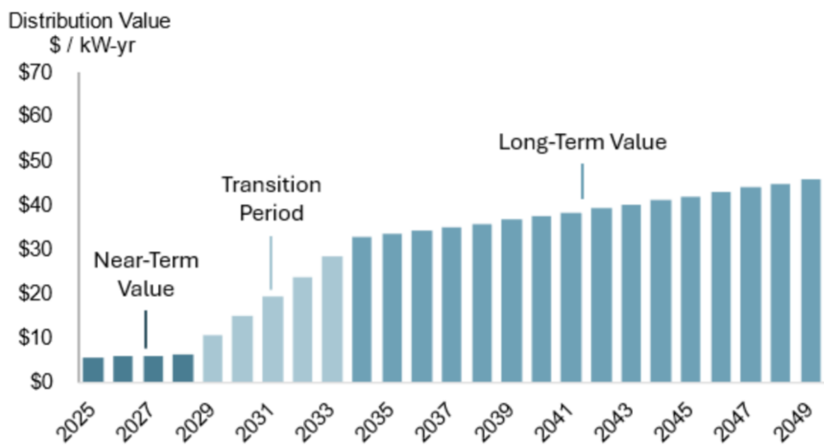
Utility	PG&E	SCE	SDG&E
Climate Zone	(simple Average)	All	All
Long Term Distribution Capacity Cost ($/kW-yr.)	$ 57.29	$ 189.53	$ 89.51

Illinois Commerce Commission (ICC): *The Value of, and Compensation for, Distributed Energy Resources in Illinois*

The *Value of, and Compensation for, Distributed Energy Resources in Illinois* report, prepared by E3 for the Illinois Commerce Commission and delivered in January 2025, uses a similar methodology to the California ACC (also maintained by E3), though utilizing different data sources regarding the distribution system long-term costs.

- The study averages out the distribution system benefits across different regions of utility service territories in order to come to a system-wide DER valuation. The report explicitly rejects using localized values, since localized values "would be very high in some individual areas of need and near zero in other parts of each utility's service territory" (p. 26). This would complicate attempts at producing a system-wide valuation of DER.
- The report also distinguishes between near-term and long-term valuations. Near-term valuations are calculated from the "bottom up" using granular data from utilities' Distribution System Plans (DSPs). These plans inform the valuation of the first 4 years. Years 10-25 are measured on a "top down" basis using the "plant and equipment" category of capital costs from utilities' FERC Form 1 filings. The report notes that although the "category does inevitably also include several types of costs which are not fully marginal or avoidable due to the adoption of DERs," it provides a reasonable approximation of the long-term benefits of DER adoption (p. 27).

Figure 10. Maximum Potential Distribution Value (ComEd, DER Installed 2025)



- The report likewise concurs that an ideal avoided cost calculator "would move toward a fully bottom-up approach to estimating distribution costs, but it requires distribution planning to involve longer-term forecasts of costs and system needs – on the scale of at least 10-20 years out" (p. 70). This would allow for "an Additive Services compensation component that provides price signals to locate those DERs in the areas of greatest need" (p. 71).

Appendix B – Long-Term Locational Value – Decision Support Tool

As inputs, the decision support tool requires:

- The current design capacity/peak load of the segment;
- The current/recent peak load on the segment, as a percent of design capacity;[16]
- The projected rate of load growth for the segment;
- The average cost of distribution system capacity upgrades, ideally derived from recent distribution capacity upgrade projects;
- The average service life of representative distribution system upgrades; and
- The utility weighted average cost of capital.

The present value of a DER based on its avoided peak load is then calculated as the difference between the cost that would have been incurred, minus the new (lower) costs for the lower capacity project. This is represented by the equation:

$$\text{PV of DER} = \underbrace{\frac{Marginal\ Costs\left(\frac{\$}{MW}\right) * CapacityIncrease}{(1+Discount\ Rate)^{\Delta tOverload}}}_{\textbf{Upgrade Cost without DERs}} - \underbrace{\frac{Marginal\ Costs\left(\frac{\$}{MW}\right) * (CapacityIncrease - DER\ Capacity)}{(1+Discount\ Rate)^{\Delta tOverload + \Delta tFromDER}}}_{\textbf{Upgrade Cost after DERs}}$$

The baseline condition *without* the DER is for an anticipated capacity level (*CapacityIncrease*) and at a future time to complete the upgrade before load growth would cause an overload (*ΔtOverload*). The distribution system upgrade cost *after* DERs is lower than the baseline condition due to two factors: it requires a lower capacity of the infrastructure (reflecting the decreased requirement due to the peak reduction from the DER, shown as *CapacityIncrease – DER Capacity*) and occurs later in time (reflecting the deferral value of the DER, shown as *ΔtFromDER*).

The required level of capacity increase for the baseline project can be estimated based on the load growth and the anticipated life of the distribution equipment, such that the equipment can accommodate all load growth over its planned service life:

$$CapacityIncrease = CircuitCapacity * (1 + GrowthRate)^{DistributionEquipServiceLife}$$

The time until the capacity upgrade is needed is calculated based on the projected rate of load growth and the current load on the segment, such that:

$$\Delta tOverload = \frac{\ln\left(\frac{1}{\%ofCurrentCapacity}\right)}{\ln(1 + GrowthRate)}$$

[this estimates the time until an upgrade would be needed, given current load and projected growth]

[16] As discussed above, distribution operators often have flexibility in shifting load across circuits to avoid overload conditions; the estimated ability to shift loads should be included as a reduction in the current peak load of the circuit to reflect these capabilities, where appropriate.

Similarly, the additional time until an upgrade is required based on the DER deployment is calculated based on the capacity of the DER compared to the overall segment capacity and the anticipated rate of load growth, such that:

$$\Delta tFromDER = \frac{\ln(1 + \frac{DERCapacity}{CircuitCapacity})}{\ln(1 + GrowthRate)}$$

[this estimates the additional time until an upgrade would be needed, given DER capacity and projected growth]

These calculations yield a present value of the DER installed today, reflecting the deferral value of distribution costs based upon current system loads and projected growth. This value can then be translated into an incentive mechanism – either a lump-sum up-front payment, or a series of payments over future years (for example, spread over the timeframe until the projected upgrade would be needed or beyond) to ensure continued performance of the DER.

Note that due to the logarithmic nature of the formula, the incremental value of DER capacity decreases with increasing DER size – reflecting diminishing returns. This is due to the fact that increasingly larger DER capacity increments provide a slightly lower time-value of savings than the initial capacity. Said another way, the value of delaying a substation upgrade from year 1 to year 2 is greater than delaying a substation upgrade from year 2 to year 3, as future years are further discounted than near-term years. Policymakers should therefore choose a DER capacity size (e.g. 1 MW) that reflects reasonable values that could be achieved over the time horizon under review, and use that value in establishing the overall segment-wide incentive levels.

Example Calculation for Estimating the Value of DERs on a Constrained Segment in the Future

	Assumed Annual Load Growth	Weighted-Average Cost of Capital (Discount Rate)	Distribution Avoided Cost - from DSP or recent capacity upgrade projects ($/MW)	Distribution Upgrade Average Service Life (years)	Distribution Capacity of Example Circuit (MW)	Example Circuit - Current % of Design Capacity:	DER Aggregation Increment (MW)
User Inputs:	1.0%	4%	$200,000	30	200	94%	5

Distribution Upgrade - Additional Capacity Needed to Meet All Load Growth through Service Life (MW)	Years until Overload at Projected Growth Rate:	Additional Years until Overload from DER Aggregation
69.6	6.22	2.4816

Year	Year	Distribution Capacity - Requirement (MW)	Projected Load (MW)	Cost of Upgrade ($)	Distribution Capacity - Requirement with DER (MW)	Projected Load With DER (MW)	Cost of Upgrade with DER ($)
0	2026	200	188	$0	200	183	$0
1	2027	200	190	$0	200	185	$0
2	2028	200	192	$0	200	187	$0
3	2029	200	194	$0	200	189	$0
4	2030	200	196	$0	200	191	$0
5	2031	200	198	$0	200	193	$0
6	2032	200	200	$13,913,957	200	195	$0
7	2033	269.6	202	-	200	197	$0
8	2034	269.6	204	-	200	199	$12,913,957
9	2035	269.6	206	-	264.6	201	-
10	2036	269.6	208	-	264.6	203	-
11	2037	269.6	210	-	264.6	205	-
12	2038	269.6	212	-	264.6	207	-
13	2039	269.6	214	-	264.6	209	-
14	2040	269.6	216	-	264.6	211	-
15	2041	269.6	218	-	264.6	213	-

Present Value of DER	
$1,722,042.75	
Capacity Reduction Portion	Time Value Portion
$783,572.94	$938,469.81
46%	54%
PV per MW	
$344,409	
Duration of Required Capacity Reduction	Duration of Time Deferral
36.2	8.7
Levelized Annual Value ($/MW-year)	Levelized Annual Value ($/MW-year)
$8,265.43	$25,969.59

Further Reading

Cutter, Eric, Jeremy Laundergan, Michael Sontag, and Margo Bonner. "Compensating DER for Local Distribution Value While Protecting Affordability: Ensuring DER Are a Grid Resource, Not a Cost Driver." Energy and Environmental Economics, Inc. (E3), July 2026, https://www.ethree.com/wp-content/uploads/2026/07/E3-LVDER-White-Paper.pdf

Fox-Penner, Peter, Sanem Sergici, Ryan Hledik, and Akhilesh Ramakrishnan. "The Role of DERs in a High-Growth, High-Cost Future." Presentation at the NARUC Summer Policy Summit, The Brattle Group, July 21, 2026. https://www.brattle.com/wp-content/uploads/2026/07/The-Role-of-DERs-in-a-High-Growth-High-Cost-Future.pdf

Lee, Michael. "While Everyone Is Talking About Data Centers, the Distribution Grid Is the Big Opportunity." *Distributed Grid*, March 12, 2026. https://distributedgrid.substack.com/p/while-everyone-is-talking-about-data