STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Commonwealth Edison Company d/b/a ComEd Verified Petition for Approval of Performance and Tracking Metrics pursuant to 220 ILCS 5/16-108.18(e).	))))))	Docket No. 25-0514

DIRECT TESTIMONY OF DAVID HILL, MANAGING CONSULTANT, ENERGY FUTURES GROUP, INC. ON BEHALF OF THE CITIZENS UTILITY BOARD AND ENVIRONMENTAL DEFENSE FUND

CUB-EDF Exhibit 1.0

July 28, 2025

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I. Introduction and Qualifications

Q. Please state your name and professional title.

A. My name is David G. Hill, and I am a Managing Consultant with Energy Futures Group, Inc., a clean-energy consulting firm headquartered in Hinesburg, Vermont, with offices in Boston and New York.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Environmental Defense Fund ("EDF") and the Citizens Utility Board (CUB) (collectively, "CUB-EDF").

Q. Please describe your current role and relevant work experience.

A. I joined Energy Futures Group ("EFG") in January of 2020. My work since then has included:

- Expert testimony filed with the Illinois Commerce Commission in Docket No. 22-0486, regarding Commonwealth Edison's initial Multi-Year Integrated Grid Plan.
- Expert report and testimony on recommended Jurisdictionally Specific Benefit Cost framework and test for use by EfficiencyOne, before the Nova Scotia Energy Board, Matter 12282.
- Analysis of Policy Options for Vermont's Thermal Sector Compliance with Global Warming Solutions Act, for Vermont Agency of Natural Resources.
- Co-author of expert report filed before the Ontario Energy Board, on Enbridge Gas Phase 2 Rebasing, EB-2024-0111.
- Expert testimony before the Rhode Island Public Utilities Commission and Energy Facility Siting Board on the long-term need for a liquid natural gas vaporization facility on Aquidneck Island.

- Expert testimony before the North Carolina Utilities Commission reviewing the equity and environmental justice aspects of Duke Energy's proposed Grid Improvement Plan in Docket No. E-2 Sub 1300.
- Expert testimony on a renewable natural gas pilot proposed by Nicor in Illinois Commerce Commission Docket 20-0722,
- Testimony on the Dominion Energy South Carolina's 2020 Integrated Resource Plan,
- Testimony before the New Hampshire Public Utility Commission on a statewide, joint, three-year energy efficiency program plan filing by the state's electric and gas utilities,
- A white paper related to amortization for gas system investments in Rhode Island,
- Testimony on proposed gas supply contract and associated on-system enhancements in New Hampshire,
- A critical analysis for the need of a proposed natural gas pipeline expansion in New York City,
- Support for testimony on the partial transfer of ownership of a coal fired power plant in Montana,
- Scenario modeling for statewide greenhouse gas reduction strategies in Massachusetts, and
- Analysis of cost recovery for utility efficiency and demand response initiatives in Maryland.

Prior to joining EFG, I worked for the Vermont Energy Investment Corporation ("VEIC") for twenty-two years, starting in 1998 as an analyst, subsequently holding several positions over the decades, serving my last five years as Director of Distributed Resources and Policy Fellow. In this position, I was responsible for advancing sustainable energy policy and program design. I regularly led major consulting assignments at VEIC, and over the years, I led or significantly contributed to the design and development of more than six large programs, with annual budgets of $100+ million, for efficiency and customer sited renewable energy initiatives in New Jersey, New York, Vermont, Arizona, Washington D.C., and Maryland. I also created and led the launch of Sun Shares, a subsidiary of VEIC to develop and provide community solar services to VEIC and its employees.

I have provided testimony in regulatory hearings on more than two dozen occasions in eight states and two provinces, and I have participated in scores of technical workshops and working groups on behalf of many clients. Further details on my work experience and education are provided in my professional resume included as CUB-EDF Exhibit 1.01

Q. Have you previously testified before the Illinois Commerce Commission?

A. Yes, I have provided direct and rebuttal testimony in Dockets 22-0486/23-0055 (cons.), 20-0722, and 21-0098 before the Illinois Commerce Commission

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit Number	Description
CUB-EDF Ex. 1.01	Professional Resume of Dr. David Hill
CUB-EDF Ex. 1.02	ComEd response to EDF DR 1.03 and Attach 1
CUB-EDF Ex. 1.03	ComEd response to EDF DR 1.14
CUB-EDF Ex. 1.04	ComEd response to EDF DR 1.15
CUB-EDF Ex. 1.05	EFG Affordability Workpapers
CUB-EDF Ex. 1.06	EFG Peak Load Reduction Workpapers

II. Summary

Q. What is the purpose of your testimony in this hearing?

A. The purpose of my testimony is to provide a critical review and analysis of Commonwealth Edison's ("ComEd" or "the Company") petition for proposed performance and tracking metrics for 2028-2031. My testimony is focused on four topic areas: 1) the value of greater transparency on the asset value of the grid, proposed investments and performance incentives, 2) the need for development of a consistent statewide benefit cost framework to evaluate the proposed multi-year grid plans, 3) improvements to the proposed affordability metric, and 4) improvements to the proposed peak load reduction ("PLR") metric.

Q. Based on your review and analysis, do you have recommendations for the Commission regarding ComEd's proposed performance metrics?

A. Yes, I recommend the Illinois Commerce Commission ("ICC" or "the Commission") direct ComEd to undertake additional work in four areas prior to approval of the proposed performance metrics.[1] These are:

1) Direct ComEd to estimate the **dollar value for each proposed performance metric and document the value per unit of performance improvement.** I discuss this recommendation in Section III. of my testimony.

i) The asset value of the distribution plant in service is not provided, and therefore the dollar value of the level of requested performance metrics incentives are unclear.

[1] I recommend the Commission direct ComEd to undertake this work as part of the grid plan development and that the revised performance metrics can be submitted for regulatory approval along with the grid plan filing.

ii) The use of percent increases and normalized baselines, along with basis points incentives or penalties, is not sufficiently clear in terms of the level of dollar incentive or penalty ComEd is requesting for each unit of under or over performance.

2) Direct ComEd and Ameren Illinois to propose and adopt a common benefit cost framework for performance metrics, grid plans and distributed energy resource ("DER") activities. I discuss this in Section IV of my testimony.

i) The process for developing a unified benefit cost framework needs to have proactive and significant stakeholder engagement and review.

ii) Recognizing development of a unified BCA test will take time and that it may not be feasible to apply to the current grid plans – I recommend the ICC still direct ComEd and Ameren to initiate or to participate (if it is led by a non-utility party) in the development of this framework.

iii) The new framework will provide statewide consistency of accounting impacts for grid investments based upon Illinois specific policy goals and objectives.

iv) ComEd's Exhibit 4.0 in this docket (25-0514) by Mr. Saeed is an example of a "check the box" mentality and approach to a benefit cost analysis ("BCA"), as opposed to application of BCA analysis to inform and influence the grid plan's development. The results from Mr. Saeed's Exhibit 4.0 are difficult to reasonably interpret or accept, as they indicate $1.28 billion of net benefits each year for maintaining a constant level of supplier diversity, for zero incremental costs.

Exhibit 4.0 missed an opportunity to build on the BCA framework begun in ComEd's Refiled Grid Plan docket, 22-0486/23-055/24-0181 (cons.).

v) Developing a consistent BCA framework will not dictate the "right level of utility spending", but grid plan investments deserve a more thoughtful application and documentation of BCA results.

vi) Consistent treatment of critical policy relevant impacts, such as greenhouse gas reductions, affordability, and peak load reductions and the associated calculation methods are needed.

3) Direct ComEd to **adopt an enhanced and expanded set of performance metric targets to better reflect the affordability impacts** of the proposed grid plan investments. I discuss this further in Section V of my testimony.

i) The Commission has identified affordability for electric service as a key performance indicator, and affordability of electric service is a critical legislative objective reflected in CEJA.[2]

ii) I recommend PM5 for disconnections be expanded to include a component for both targeted ZIP codes (PM5.1) ***and*** for the general residential population (PM5.2).

iii) In addition to the recommended PM5.1 and 5.2 for reductions in disconnections, I recommend the Commission direct ComEd to document and report on electricity burden for target ZIP codes as a tracking metric. Electricity burden is a holistic metric for assessing affordability impacts, is manageable with

[2] *E.g.*, 220 ILCS 5/16-108.18(a).

existing utility and census data,[3] and should be required as a complement to the disconnection performance metrics. My recommendation regarding PM5.1 and 5.2 assumes ComEd agreeing to my proposed electricity burden by ZIP, otherwise I reserve additional recommendations regarding PM 5 for my rebuttal testimony.

4) Direct ComEd to adopt peak load reduction targets based on the achievement of percentage of peak load based on the 2023 system peak.[4] I propose an increasing, stepwise target for ComEd to establish the baseline savings goal used for its performance metric, starting with 1% savings of 2023 peak load in 2028, increasing to 2% in 2029, 3% in 2030, and 4% in 2031.

i) I also recommend the Commission direct ComEd to propose a demand response ("DR") potential study for approval in their next Grid Plan, to assess a comprehensive set of resources and associated estimates of achievable peak demand savings over a 10-15 year planning horizon. ComEd should conduct this study and complete associated planning and program design prior to the next Performance Metrics proceeding, so that program-specific annual savings targets can inform future PLR. The performance incentives for the 2028-2031 periods should be contingent upon ComEd completing this study.

ii) I recommend maintaining the symmetrical performance incentive structure and using the proposed distribution of achievement thresholds ComEd has proposed for earning basis points (translated in terms of percentage achievement of baseline, and

[3] In response to EDF 1.14, ComEd indicates it already tracks electricity burden as an indicator of affordability, but the Company thinks including it as a tracking metric would be "problematic". CUB-EDF Ex. 1.03. I address ComEd's concerns below in Section V. p. 17.
[4] The 2023 baseline for the system peak and peak load reduction metric could be updated pending more current data.

the associated MW values). ComEd should earn performance incentives for achieving reductions above the expected incremental growth of its peak load savings resources.

iii) The Commission should direct ComEd to make explicit reference in this docket to energy efficiency/demand response co-deployment strategies to effectively scale DR savings.

iv) The Commission should provide guidance, clarifying whether ComEd's load management strategies are to consider impacts for the whole system footprint, or only for the subset of retail supply customers. I recommend clarifying that impacts for the whole system footprint should be considered.

iv) The Commission should require ComEd to include the additional tracking metrics (listed in this testimony below in Section IX) related to the development and performance of programs, resources, and technologies that contribute to peak load savings.

III. Performance Metric and Grid Plan Fundamentals: Value of the Grid Asset, Proposed Spending, Proposed Value of Performance Metrics

Q. What is the basis for ComEd's proposed performance metrics?

A. ComEd provides electric service to more than 3.7 million residential customers in Illinois through roughly 5,300 miles of transmission and 64,600 miles of distribution lines. The incentives and penalties at stake here should leverage ComEd's interest in that rate base to cost-effectively align ComEd's financial interests with its customers' interests in better reliability, resilience, equity, affordability, environmental sustainability, customer service, and supplier diversity. As indicated in Ms. Perkins' testimony (ComEd Exhibit 1.0), ComEd is proposing performance metrics for the next 2028-2031 multi-year grid plan in response to the performance-based electric delivery service ratemaking framework established by the Climate and Equitable Jobs Act (CEJA).[5] Section 108.18(e) of the Act indicates the Commission can approve up to eight, but no fewer than six performance metrics for a particular multi-year rate plan.[6] Each performance metric may include multiple indices.

Q. Do you have any high-level comments on the performance metric presentation and how it relates to the utility grid as an asset and opportunities to improve performance through the grid investment plan?

A. Yes. The performance metric petition, and in its time the subsequent grid investment plan, can be greatly improved by directly and transparently addressing some key pieces of information that are currently missing.

Q. What are these key pieces of missing information? [7]

A. The proposed performance metrics are based on adjustment to ComEd's return on equity for the multi-year plan. As proposed, across the metrics, good performance is rewarded by increasing the return on equity by a total of no less than 20 and no more than 60 basis points (1 basis point equals 1/100 of a percent). Ms. Perkins notes that the Company is proposing symmetric performance incentives/penalties that allocate 29 basis points across 8 performance metrics.[8] The first critical piece of missing information is the size of the rate-base to which the requested additional rate of return applies.

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[5]ComEd Ex. 1.0 at 4:70-77.
[6] 220 ILCS 5/16-108.18(e).
[7] EDF submitted data requests to ComEd regarding the asset value to which basis points will be applied and to historic and proposed levels of grid plan spending. At the time this testimony is being drafted the discovery responses have not been provided.
[8] ComEd Ex. 1.0 at 6:109.

Of course, a provisional or historical estimate is needed until the multi-year plan is filed. Nonetheless, it is essential, for regulatory review and for consumer and ratepayer transparency, to have as clear a sense as possible with available information of the value of the asset base against which performance incentives will be calculated. For example, if the equity component of the rate base is $1 billion, 29 basis points of annual performance incentives or penalties are equal to $2.9 million. However, if the equity component of the asset base is $8 billion, the annual value of 29 basis points is $23.2 million.[9] In any case the petition for the requested performance incentive should be grounded in a clear understanding and statement of the asset value to which the basis points are applied. Below in Section VII, I use a minimum estimate of $17.3 billion and 50% equity using figures for ComEd's rate base at the end of calendar year 2027, all figures from ComEd's most recent multi-year rate plan.

Information on the total asset value of the electric utility grid also provides context for the proposed levels of investments. Historic spending levels and the total asset value of the grid help parties – legislators, energy system planners, regulators, advocates and the public – put proposed spending into perspective. While the grid plan, rather than the performance metric filing, may be the more appropriate venue to fully explore and present proposed and historic spending levels, those spending levels are interrelated, and this information provides important context in this docket for both the value of the requested incentives and the levels of proposed performance attainment.

Q. Can ComEd's performance metric filing and subsequent grid plan be improved by providing this background and context information?

[9] Calculated (29/100)%*$8billion = $23.2 million.

A. Yes. The performance metric filing should estimate the value of the requested incentives in clear and direct terms in dollar value. Though the final values might be modified based on differences in the ultimately approved asset base and level of grid spending, which is a matter for separate dockets, an initial transparent dollar estimate based on then-available information for each metric should be required in the performance metric filing. The grid plan, and I would suggest the performance metric ***and*** grid plan filings, should start with basic context and background, including, but not necessarily limited to:

A) The value of the utility's grid asset, and the equity component of that asset on which the value of a return on equity performance incentive is calculated, [10]

B) How that value has changed over time,

C) The estimated level of spending to maintain/enhance the grid asset in the pending plan, and

D) The units of improvement enabled by the plan, and how many dollars of incentive are requested for each unit of performance improvement.

IV. Benefit Cost Analysis

Q. Should the utility grid plans be evaluated for cost effectiveness?

A. Yes, although I am not a lawyer, my analysis is informed by my reading of Illinois statute 220 ILCS 5/16-108.18. The statute uses the term "cost-effective" several times, including where it says the Commission shall approve "performance metrics that, to the extent practicable and achievable by the electric utility, encourage cost-effective, equitable utility

[10] Note that information on the asset value of the grid need not divulge any information of concern with regards to critical infrastructure security or sensitivity but can be at an appropriately aggregate level to inform regulatory oversight and review of performance metrics and proposed investments.

achievement" of the metrics listed in the statute.[11] My analysis is also informed by my reading of the Commission's Order on Refiling in ComEd consolidated Multi-Year Grid Plan and Rate Plan docket, issued on December 12, 2024.[12] The order noted the Commission's rejection of ComEd's prior grid plan because it lacked a cost benefit analysis (CBA) or other cost-effectiveness framework, and approved the Company's refiled grid plan because it adopted an updated cost-effectiveness framework. Grid plans deserve to be evaluated using a common, clearly articulated benefit cost analysis (BCA) framework since they represent large and very important investments in a valuable societal asset. ComEd witness Perkins notes that the Commission decided in 22-0067 that a CBA will "certainly aid in the Commission's analysis."[13] Since then, the Commission agreed with Commission Staff in ComEd's Refiled Grid Plan that "to the extent practicable, the Company provide a BCA for investment intended to support the achievement of performance metrics rather than applying a LCBF [least-cost best-fit] standard analysis."[14] In my opinion, the Commission's reasoning on BCAs in Docket 22-0486/23-005/24-0181 (cons.), should be extended to this docket, and the Commission should require a BCA where practicable to aid the Commission in evaluating the extent to which grid investments are cost effective.

Q. Do you have any comments on the benefit cost analysis presented by ComEd in the Company's application?

A. ComEd presents the BCA results for each of the proposed performance metrics separately in Exhibits 2.0 to 7.0. These presentations illustrate the need for more and better attention to the BCA framework and quantification. For example, the BCA results for supplier

[11] 220 ILCS 5/16-108.18(e)(2).
[12] Order on Refiling at 32-37, ICC Dkt. No. 22-0486/23-0082/24-0181 (cons.) (Dec. 19, 2024)
[13] ComEd Ex. 1.0 at 14:244.
[14] Order on Refiling at 37, ICC Dkt. No. 22-0486/23-0082/24-0181 (cons.) (Dec. 19, 2024)

diversity presented by Mr. Saeed in Exhibit 4.0 are highly questionable. The proposed supplier diversity performance metric (PM4) is to maintain a level of 45% of the total annual vendor spending that is diversity-certified.[15] The BCA results presented by Mr. Saeed in Table 21 rely on a regional economic impact study conducted by Concentric Energy Advisors using the IMPLAN model.[16] IMPLAN model results typically include direct, indirect, and induced spending impacts on local jobs and economic activity. The model suggests the diversity supplier portion of spending created $1.28 billion of value in 2024. ComEd treats this as a benefit and assumes that there are no program costs to achieve it so that the net benefits of the supplier diversity metric are $1.28 billion per year.

There are several problems with this conclusion. First, BCAs measure whether economic benefits exceed economic costs of an investment. Another way to think about that is that BCAs measure whether costs will go up or down as a result of an investment. Economic development and jobs are not economic "costs" or "benefits" that belong in a BCA. To be sure, this type of regional macroeconomic analysis can complement a BCA test by estimating broader economic impacts not included in a BCA test, but this type of analysis does not replace or belong in a BCA test. Second, the impacts of the diversity spending should be estimated in relation to a "baseline" level of spending. In other words, ComEd should assess the macroeconomic impacts of prioritizing supplier diversity by comparing the magnitude of diverse jobs that would result both with and without a supplier diversity initiative. To assume that there will be zero diverse suppliers without such an initiative is not reasonable. Nor is it reasonable to assume that there is no cost to such an initiative. For example, if it is expected that some of the contracts that will be awarded to diverse

[15] *See* ComEd Exhibit 4.0, Table 21 at 241.
[16] The Concentric Energy Advisors Study is ComEd Exhibit 4.01.

suppliers will be awarded because they are diverse, there may be slightly higher costs incurred (there would be no need to prioritize diversity in contract awards if diverse suppliers would always win based on price and other factors other than diversity). The costs and benefits for meeting the metric need to be based on the activities specifically undertaken to increase supplier diversity. The analysis presented by ComEd appears to mistakenly assume that without the supplier diversity metric the diverse supplier portion of new grid investments would not occur. The reporting of these BCA results in ComEd's Exhibit 4.0 underscores the need for development and careful review of a common BCA framework for evaluation of the performance metrics to inform the Company's grid plans.

Q. Do you have other comments on the proposed supplier diversity performance metric?

A. Yes, my other concern with ComEd's supplier diversity PM4 is the Company's proposal to change from the prior refiled grid plan's level of +/- 3 basis points for supplier diversity to assigning zero basis points for this metric.[17] My understanding is that a performance incentive means that some basis points must be involved. Having no incentive/penalty associated with PM4 effectively means it is not a true performance metric but rather a tracking metric. The Commission has been clear that the CEJA requires at least one performance metric per enumerated category, and supplier diversity is one of these categories. Thus, it follows that there must be at least one supplier diversity performance metric with some non-zero amount of basis points assigned to it.

Q. Do you have other concerns or comments on the benefit-cost analysis?

A. Yes. ComEd's exhibits illustrate their approach to presenting and evaluating the BCA results for each performance metric independently.[18] The evaluation of a multi-year grid

[17] ComEd Ex 1.0, Table 1 at 204.
[18].ComEd Ex. 1.0 at 250-253.

plan application and performance metrics needs to account for the combined and interactive impacts of the proposed investments. Specifically, it is problematic to assess the cost-effectiveness of meeting just one metric because it will often be impossible to assess how much of proposed grid investment is associated with just one metric in isolation from all the others. The benefits associated with multiple metrics can also be overlapping. The development of a comprehensive benefit cost analysis that appropriately captures all the impacts with material relevance for Illinois policy objectives, while avoiding double counting of impacts, is a complex, yet manageable, undertaking.

Q. Are there resources available to help utilities and other stakeholders design and develop a jurisdictional specific benefit cost test for Illinois?

A. Yes. The National Standard Practice Manual[19] ("NSPM") provides guidance and resources to promote the development of jurisdictionally appropriate, policy relevant, BCA framework and quantification of impacts.[20] The NSPM is currently or recently being used in Virginia, Maryland, Michigan, Minnesota, the District of Columbia, and Nova Scotia to guide the development of jurisdictionally specific BCA tests.[21] The NSPM principles include guidance on why and how to avoid double counting impacts.

Q. At a high level, what are some of the benefits of the Commission directing the Company to work with stakeholders to develop a BCA framework and jurisdictionally specific BCA test?

A. Continuing the transparent stakeholder process undertaken in the Company's refiled grid plan to further develop a BCA will better inform grid planning investments and

[19] https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/
[20] One of EFG's founding Partners, Chris Neme is a contributing author to the NSPM and has given trainings on its use and application. EFG has advocated for and supported adoption of the NSPM in Maryland and Nova Scotia.
[21] https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/nspm-application-by-state/

prioritization, through systemic estimation and accounting of impacts. One example of how it could change plans and outcomes is by enabling higher levels of third party DER engagement and participation. An improved BCA framework does this by reducing risk for potential DER providers by providing a clearer indication of how options (for example virtual power plants, and other non-wire alternatives) are compared to conventional grid investments.

Q. Given these observations, what process would you recommend for the further development of a benefit cost framework and jurisdictional specific test for evaluation of grid plan investments?

A. While it is too late to undertake this activity for application to the current multi-year grid plan, I recommend the Commission direct parties to convene and complete within a reasonable timeframe (in time for use in development of the next grid plan), the development of an Illinois jurisdictional specific test for use in future grid plan and other electric utility system planning and investment dockets. This recommendation is consistent with, but broader than, CUB-EDF's recommendation in EFG's 2023 grid plan testimony (for ComEd) to develop a jurisdictional specific test for evaluation of non-wire alternatives.

V. Affordability Impacts

Q. How can grid investment plans impact affordability?

A. Investments to maintain or enhance electric grid services can lead to increasing rates and bills, making electric service less affordable. Alternatively, they can reduce overall system costs, rates, and customer bills, making electric service more affordable. There are complicated and dynamic tensions between these two outcomes, and a mixed set of results may often emerge. These tensions and dynamics underscore the importance of an affordability performance metric.

Grid investment and grid modernization plans should explicitly include measures and programs that are cost-effective – i.e., those that address system needs less expensively than traditional electricity infrastructure alternatives. Generally, when system costs are reduced, affordability should be improved. However, this does not always hold. For example, increased investment in a distributed energy resource management ("DERMS") system increases the overall electric system costs and revenue requirements, but simultaneously enables reductions in customer electric bills, or overall energy burden, by enabling on site generation, storage, flexible demand, or electrification, which are financially advantageous for the host customer. Electricity, and increased bills for electric service, can function to reduce a household or business's total energy burden when more expensive fossil fuels are displaced.

Q. What metric is ComEd proposing to assess affordability impacts?

A. ComEd's proposed performance metric 5 ("PM5") is to reduce aggregate disconnections in 20 ZIP codes with the highest historical disconnection rates.[22] The Company proposes to reduce the aggregate payment related disconnections in 20 target ZIP codes (to be identified) by 10% year over year and with a symmetrical allocation of +/-5 basis points to this metric.[23] The affordability metric is discussed in more detail by Mr. Bohn in ComEd Exhibit 5.0. A reduction in aggregate disconnections for target ZIP codes was proposed and approved by the Commission as the affordability impact metric for the current 2024 to 2027 plan.

[22] ComEd Exhibit 1.0, Table 1 at 204 .
[23] *Ibid.*

Q. Is a performance metric based on disconnections a good measure of affordability to determine if electricity service is a manageable portion of household incomes?

A. A performance metric based on disconnections measures one aspect of affordability, namely energy insecurity. A service disconnection for non-payment is an unfortunate "end-point" indicator of electric service not being affordable. While I recommend the disconnection metric be maintained as the primary affordability metric, I also recommend a tracking metric that tracks and reports on electricity burden for a target set of most at risk customers as a pre-requisite for my recommendation regarding any affordability performance incentives.

Q. What information does ComEd provide in its performance metric filing on the absolute number of disconnections and disconnection rates?

A. The performance metric filing discusses disconnections in terms of percent decrease in the number of aggregate disconnections in target ZIP codes. It does not present data on the absolute number and/or the percentage share of residential customers who experience disconnections.[24] The absolute number of disconnections and disconnection ratios provide important context for the definition of a metric, and for analysis of the appropriate performance-based target. I recommend that the Commission direct ComEd to include this information.

Q. Have you investigated the absolute number of disconnections and disconnection ratios in more depth?

A. Yes. In response to EDF 1.15 (CUB-EDF Ex. 1.04), ComEd provided a citation to the monthly Credit, Collections, and Arrearages Reports filed with the Illinois Commerce

[24] A simple disconnection ratio is the annual number of disconnections divided by the number of accounts.

Commission.[25] After reviewing the 2024 annual report, I learned that ComEd suspended disconnections for an extended period in 2024 due to billing system issues.[26] My review of the 2023 workbook indicates ComEd reported 196,962 disconnections in 2023, resulting in a disconnection ratio impacting roughly 5.26% of their 3,746,852 residents.[27] Low-income customers had a higher disconnection ratio with 28,012 disconnections reported from a population of 186,523 accounts, representing a 15.02% disconnection ratio.[28] Further sorting the data, the twenty ZIP codes with the highest number of disconnections had 11,508 disconnections out of 62,721 residential accounts, the equivalent of a 18.35% disconnection ratio.

Q. What would ComEd's proposed PM5 of 10% annual reduction in aggregate disconnections be equivalent to, if applied to the 20 ZIP codes with the highest number of 2024 disconnections?

A. ComEd has not identified the set of 20 ZIP codes for the proposed PM5. To investigate, I used the 20 ZIP codes with the highest number of avoided disconnections in 2023 and estimated that a 10% reduction each year equates to an average of 989 annual avoided disconnections over 2028 to 2031.[29] Based on an estimate of a $17.3 billion asset base with 50% equity, the annual value of the proposed performance incentive of +/- 5 basis points for a 10% annual reduction in the aggregate number of disconnections in the target Zip codes is "+/- $4,325,000".[30] Dividing this by the average annual number of avoided

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[25] 220 ILCS 5/8-201.10(a). Credit and Collections and Arrearages Annual Reporting filed by ComEd on 4/29/2025.
[26] 220 ILCS 5/8-201.10 (a): Credit and Collections and Arrearage Annual Reporting filed by Commonwealth Edison Company on 5/1/2023
[27] *See*, CUB-EDF Ex. 1.05, ComEd Afford Workpaper, Sum of Col G divided by Sum of Col. E.
[28] *Ibid.* Sum of Col. K divided by Sum of Col. I. see workbook row 572 and below for calculations.
[29] 11,508 Baseline disconnections for Top 20 ZIP codes in 2023, total reduction of 3,958 disconnections, 4-year average 989.
[30] The actual rate base will depend upon the approved rate plan, but an estimate based on historical and or projections of that value is essential to allow for calculation of the value of the requested performance incentive.

disconnections indicates the value of the requested performance incentive is roughly $4,371 per avoided disconnection.

Q. How does your estimate of the approximate value of the requested performance incentive per avoided disconnection compare to data on average arrears for disconnected residential customers?

A. I have not been able to review the average arrears for disconnected customers for ComEd, but I expect the requested utility performance incentive is much higher than average arrears for customers who are disconnected. For illustrative purposes, I looked to the arrearage data presented in Ameren Illinois' performance metric docket 25-0574, which indicates residential non-payment disconnections have average account arrearages ranging from $646 to more than $1,424 dollars.[31] ComEd does not clearly present their request for a utility performance incentive that is likely much higher per avoided disconnection than the average arrears of customers facing disconnection. The Company's performance metric application obscures this outcome through an unnecessarily opaque presentation and discussion of the metric, wherein reductions are presented in percent and basis point terms, and not in terms of actual dollars requested and associated avoided disconnections. The Company's opaque presentation of its proposal underscores the importance of performance metric filings including an estimated value of the requested incentives in clear and direct terms, in dollar value, as discussed above in Section III of my testimony.

Q. Does ComEd's petition provide information on the estimated costs and benefits of the affordability metric PM5?

[31] ICC Docket No. 25-0574, CUB-EDF Ex. 1.03, Ameren Illinois response to EDF Data Request EDF 1.07, available at https://www.icc.illinois.gov/docket/P2025-0574/documents/368259/files/645217.pdf. .

A. It does partially. ComEd's Exhibit 5.0 submitted by Mr. Bohn states while there will be both qualitative and quantitative net benefits for the avoided disconnections, he concludes these are hard to quantify and does not provide specific estimates or benefit cost calculations.[32] Mr. Bohn indicates there are no incremental costs for ComEd attaining the affordability performance metric,[33] further calling into question the rationale for requesting a performance metric incentive of more than $4,300 per avoided disconnection. It also suggests the Company does not think there are incremental actions and costs it can take to reduce disconnections for target low-income households.

Q. Do you have recommendations to improve the structure and levels of ComEd's proposed affordability performance metric?

A. Yes. I recommend the following.

1) For the target 20 ZIP codes, I recommend a target reduction in disconnections over four years sufficient to reduce the disconnection ratio to <12% in the fourth year.[34] The target 20 ZIP codes still need to be identified by the Company and need to account for a minimum population size and be reflective of the ZIP codes with the highest disconnection rates. To analyze my recommendation, I looked at the 20 ZIP codes with highest absolute number of disconnects for 2023 from the Company's reports, and calculated the reductions necessary for a disconnection ratio of <12.0% after four years requires an absolute reduction of 3,981 from the 2023 reported number of 11,508 disconnections from the top 20 low-income ZIP codes. The reduction of disconnections for target ZIP codes would be PM5.1.

[32] ComEd Ex. 5.0, section B. Net Benefits lines 169-197.
[33] *Ibid.* lines 194-195.
[34] Annual targets should be established using the recommended 4-year target as a basis.

2) I recommend a performance metric target for the general residential population of a reduction in disconnections over four years sufficient to reduce the general residential population disconnection ratio to 4.0%. Based on ComEd's 2023 disconnection reported data, this would be a reduction in residential disconnections of 47,088, from 196,692 in 2023 to less than 149,874 in 2031. The general population reduction in disconnections would be PM6.2. The avoided low-income disconnections are a subset of, and should count toward, the total general population number of avoided disconnections. The required number of avoided disconnections for the target 20 ZIP codes **and** for the total reduction from the general population both need to be met to achieve the full performance incentive.

These levels of recommended reductions in disconnections would be required for a 5-basis point performance incentive reward. I recommend the utility be required to attain half of the proposed performance PM5.1 and PM5.2 targets before any incentive is awarded (the zero balance point). The incentives would scale linearly from the 0-balance point to the maximum incentive level, and symmetrically as a penalty to negative 5 basis points for reductions less than the proposed zero balance point. Table 1 illustrates the recommended structure with goals and balance point disconnection ratios, avoided disconnections and remaining disconnections in each year 2028-2031 based on 2023 baseline data and an even allocation of the target across the four years. The final actual values will need to be based on ComEd identification of the target ZIP codes, and the latest available data (or an agreement on an appropriate year(s)), to set a benchmark.

Table 1 Recommended Performance Metric Levels

	Disconnection Ratios	2023 Benchmark	2028 Balance point	2028 PM6	2029 Balance point	2029 PM6	2030 Balance point	2030 PM6	2031 Balance point	2031 PM6
PM 5.1	Target Zip	18.35%	17.55%	16.76%	15.97%	15.17%	14.38%	13.59%	12.79%	12.00%
PM 5.2	General Res Pop	5.26%	5.10%	4.94%	4.79%	4.63%	4.47%	4.31%	4.16%	4.00%
	Reduced Disconnections Absolute from 2024									
PM 5.1	Target Zip	NA	498	995	995	1,991	1,493	2,986	1,991	3,981
PM 5.2	General Res Pop	NA	5,886	11,772	11,772	23,544	17,658	35,316	23,544	47,088
	Reported (2024) and Projectd Remaining Disconnections									
PM 5.1	Target Zip	11,508	11,010	10,513	10,513	9,517	10,015	8,522	9,517	7,527
PM 5.2	General Res Pop	196,962	191,076	185,190	185,190	173,418	179,304	161,646	173,418	149,874

I recommend the eligibility for all PM5 incentives requires meeting or exceeding the balance point for PM5.1 for target ZIP codes. If this minimum criteria is met, then the level of incentive would be based on the lesser of the calculated basis point award for PM5.1 and PM5.2. To reach the full 5 basis point incentive both PM5.1 and PM5.2 would need to exceed each year's PM5 levels. An alternative to my recommendation is to assign 2.5 basis points each to PM5.1 and PM5.2, with attainment of the PM5.1 balance point a minimum requirement for any annual PM5 incentive.

Q. To achieve these disconnection figures by 2031, what annual targets should the Commission set for disconnections?

A. As estimated in Table 1 above (which presents an illustrative case using ComEd's reported 2023 disconnections as a baseline for the top 20 ZIP codes), the cumulative reduction in disconnections required to meet the full performance incentive are: for 2028, 995 reduced disconnections, for 2029, 1,991 reduced disconnections, for 2030, 2,986 reduced disconnections and for 2031, 3,981 reduced disconnections.

For the general residential population, the cumulative reductions in disconnection targets by year for the full proposed incentive are: for 2028, 11,772 reduced disconnections, for 2029, 23,544 reduced disconnections, for 2030, 35,316 reduced disconnections, and for

2031, 47,088 reduced disconnections. Reduced disconnections from the 20 target ZIP codes would count toward the reduction in the general population, but the target ZIP code metric reductions must be met for either PM5.1 or 5.2 to be awarded.

Q. Why is it important to include annual performance targets, instead of resetting the baseline each year?

A. It is important not to reset the baseline based on over- or under-performance each year since doing so tends to create unintended consequences. For example, if the utility overperforms one year, it makes it unfairly difficult to achieve the target the next year. At the same time, if a utility underperforms one year, resetting the baseline avoids the ultimate target of <12% in the target ZIP disconnection ratio by year 4.

Q. Do you recommend any additional requirements for PM5?

A. Yes. As indicated in the lower set of rows in Table 1, the remaining number of annual disconnections, even after ComEd meets or exceeds the performance metric target, is high and of potential concern. Therefore, to improve visibility and understanding of electric service affordability, I recommend the Commission require ComEd include a tracking metric of residential electric bill burden as a share of median census block or ZIP code household income. In response to EDF DR 14, the Company stated "ComEd already uses electric bills as a share of household income in assessing the affordability of its Multi-Year Grid Plan."[35] They also state that using this as a performance or tracking metric is problematic since there are external factors influencing the electricity burden that are not in the Company's control. Acknowledging that not all elements are in the Company's control, I recommend the electricity burden be formally adopted as a tracking metric.

[35] Response to EDF 14.

Tracking and reporting on the electric bill burden as a share of median household income provides an important complementary measure of affordability. This will help to inform future efforts and needs for more actions to improve affordability. I am not recommending a variable penalty or incentive be directly awarded or assessed on my proposed energy burden tracking metric, but my recommendation on the utility eligibility for PM5.1 and PM5.2 incentives is contingent on the completion and Commission approval of this tracking metric.

Q. **Have you estimated what the requested performance incentive per reduced disconnection would be if your performance levels were adopted?**

A. Yes, again using the 2023 baseline for an illustrative example, under my proposed structure the annual estimated value of 5 basis points of $4.325 million can be divided by the reduced disconnections from the general population, which in 2028 are 11,772, to arrive at an estimated performance incentive award of $367 per avoided disconnection. This is more reasonable than ComEd's proposed award of $4.325 million for 989 average annual reduced disconnections in the target ZIP codes, which is equivalent to an incentive award of $4,371 per avoided disconnection. I anticipate there will be incremental costs to attain the higher levels of reduced disconnections, and ComEd will need to account for these. Measures and actions that are under the utility's control that could be taken to increase the number of reduced disconnections include more proactive weatherization, supporting and promoting higher adoption rates for the low-income tariffs, and increased targeted customer assistance.

VI. Peak Load Reduction Impacts – Background and Definitions

Q. Does the statute require utilities to have a peak load reduction metric?

A. First, as noted earlier, I am not a lawyer and, throughout this testimony, I am not offering a legal opinion, but my own interpretation and understanding. With that said, yes, it is my understanding that the statute does require a PLR metric. Section 16-108.18(e)(2)(A)(ii) of the Illinois Public Utilities Act states that a utility must include one performance metric to "reduce peak load attributable to demand response programs."[36]

Q. Does the statute provide definitions of "demand response"?

A. Yes, it states: "'Demand response' means measures that decrease peak electricity demand or shift demand from peak to off-peak periods." [37]

Q. Does the statute define "peak electricity demand" or "peak" or "off-peak" periods?

A. No. The statute does not define those technical terms. The Energy Information Administration ("EIA") defines peak demand as: "the maximum load during a specific period of time."[38] The specific period typically aligns with hours within a given day, week, season, or year when electricity demand is highest or at times of supply constraints. These specific hours are also typically variable for a given utility territory based on the profile of customer hourly demand, geography or location where these occur on the localized grid, and the associated supply side resources used to meet this demand. While peak periods are often associated with the maximum load at the system level, relative to power supply or generation for a utility territory or region, peak can also refer to localized peaks that impact power supply at the distribution level. Depending on specific design and deployment features, resources like demand response have opportunities to provide grid value in reducing or shifting load associated with both system and local level peak periods.

[36] 220 ILCS 5/16-108.18.
[37] 220 ILCS 5/16-108.18.
[38] Glossary - U.S. Energy Information Administration (EIA), https://www.eia.gov/tools/glossary/?id=electricity.

In terms of demand response, "peak electricity demands" should be understood as any maximum load occurring at a specific time period, with "peak" reflecting either system or local peak demand. A system-level peak could occur and refer to a peak event within the PJM region or specifically for ComEd's operating system. A local-level peak could occur and refer to a peak event occurring within a specific component of a utility distribution system, resulting in localized capacity constraint for a specific feeder or substation boundary. Demand response, as well as other resources, provide additional demand flexibility that can be responsive to peaks occurring at different times and different locations, under the variable definitions of peak described above, contingent upon the specific application and all in service for providing additional value at the customer, grid, and societal levels.

Specifically for the PLR, as explained in the Multi-Year Performance and Tracking Metrics Manual (Ex. 1.01 PM Manual), ComEd's proposed performance appears to be defined relative to a system peak, though this is not explicit. One category of programs (3A) is defined by cleared capacity for applicable DSM programs bid into the PJM Load Management Capacity market, which relates to wholesale system-level peaks. The other category of programs (3B) are those not bid into PJM and are proposed to measure the total MWs of reduced capacity obligation. While this second category of programs are not bid into the wholesale market, reduction of ComEd capacity obligation suggests a primary focus on system level value, rather than using these resources for local grid value. While the proposed PLR is in reference to system peak loads, these resources developed and used to achieve PLR targets have flexibility to be used in various applications to optimize grid value, including at the local level.

Q. Is this definition consistent with common definitions of demand response?

A. Yes, this is generally in line with common definitions of demand response, which typically focus on ability to reduce or shift peak loads.

The Federal Energy Regulatory Commission uses the following definition of demand response, noting changes to energy usage are made in response to incentives or price of electricity:

> "Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." [39]

In practice, many utilities include a broad suite of offerings within the label of demand response. These include direct load control ("DLC") of devices, appliances, and end-use loads; time-varying rates ("TVR") or dynamic pricing offerings; behavioral demand response ("BDR") programs; third-party aggregation or customized DR and initiatives involving managing peak loads of electric vehicles, charging equipment, and energy storage systems.

Q. Does the statute define what resources, technologies, or programs are included within its definition of "demand response"?

A. No, it does not provide a discrete list or examples of resources, technologies, or programs that are included under its definition of demand response.

Q. How does demand response relate to the concept of demand flexibility?

A. At the core of most definitions of demand response is the ability for demand-side management ("DSM") resources or DERs to alter their consumption at specific times, in

[39] Reports on Demand Response and Advanced Metering | Federal Energy Regulatory Commission, https://www.ferc.gov/power-sales-and-markets/demand-response/reports-demand-response-and-advanced-metering.

response to specific signals or interventions. This definition of demand response is directly related to the concept of demand flexibility. Lawrence Berkeley National Laboratory defines demand flexibility as:

> "Demand flexibility is the capacity of demand-side loads to change their consumption patterns hourly or on another timescale."[40]

Effectively, demand-side resources, like demand response products and other DERs, can unlock demand flexibility potential, allowing utilities to change consumption patterns at various times to provide grid value, including system and localized peak periods. DSM resources like energy efficiency and demand response can also be considered DERs.[41] Demand flexibility is an inherent capability of demand-side resources like demand response, which can be used to reduce or shift load from peak periods (either system or local level peaks) to off-peak periods to alleviate grid constraints or limited power supply in relation to high customer demand.

While the statute does not explicitly define "peak," it does allude to the value of flexibility, which implicitly regards definitions of peak and how resources like demand response can be used to provide grid value. Specifically, the statute acknowledges the value of flexibility in requiring tracking metrics:

> "Enhance the grid's flexibility to adapt to increased deployment of nondispatchable resources, improve the ability and performance of the grid on load balancing, and offer a variety of rate plans to match consumer consumption patterns and lower consumer bills for electricity delivery and supply." [42]

Q. What programs or initiatives does ComEd include within its definition of demand response used to target peak load reduction?

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[40] Demand Flexibility | Building Technology and Urban Systems, https://buildings.lbl.gov/demand-flexibility.
[41] Grid Modernization Laboratory Consortium, Distributed Energy Resources (DER) (Na. 16-17, 2018), https://eta-publications.lbl.gov/sites/default/files/4._coddington_stewart_oneil_ders_updated.pdf.
[42] 220 ILCS 5/16-108.18

A. In ComEd Ex. 1.01 (12-14), the Multi-Year Performance and Tracking Metrics Plan provides an overview of details regarding PM 3: Peak Load Reduction performance metric. While no specific programs are listed in this Plan, ComEd defines two components of the PLR or program categories contributing to PLR peak load impacts: (3A) cleared MW savings associated with applicable programs under its DSM portfolio that participate in the PJM Load Management Capacity market, and (3B) total MW of capacity obligation reduced from any demand response programs within its DSM portfolio not bid into the PJM capacity market.

In response to EDF 1.03, ComEd provided a workbook with forecasts of DSM programs as part of the PLM performance metric for the 2023-2027 period.[43] Within this workbook, it includes the following programs:

- Peak Time Rebates ("Peak Time Savings")
- Air Conditioning Cycling ("AC Cycling")
- Real Time Pricing ("Hourly Pricing")
- Battery DLC (via "Community Solar + Storage")
- Smart Thermostat DLC (via "Smart Thermostat Portion" of its VPP)
- Battery DLC (via "BTM Battery Portion" of its VPP)
- Non-Residential Load Curtailment ("Mandatory Load Response")

Q. What DSM or DER programs are commonly considered within the definition of demand response, providing demand flexibility including capability to a potential to contribute to peak savings?

[43] CUB-EDF Ex. 1.02

A. Eligibility of programs that contribute to the PLR should be proactively defined by the utility in their application, and then approved or modified by the Commission. In my opinion, there is a broad range of programs, technologies, and strategies that are typically considered demand response resources and should be considered by ComEd in developing a flex load resource portfolio qualified for the Peak Load Reduction metric. These include:

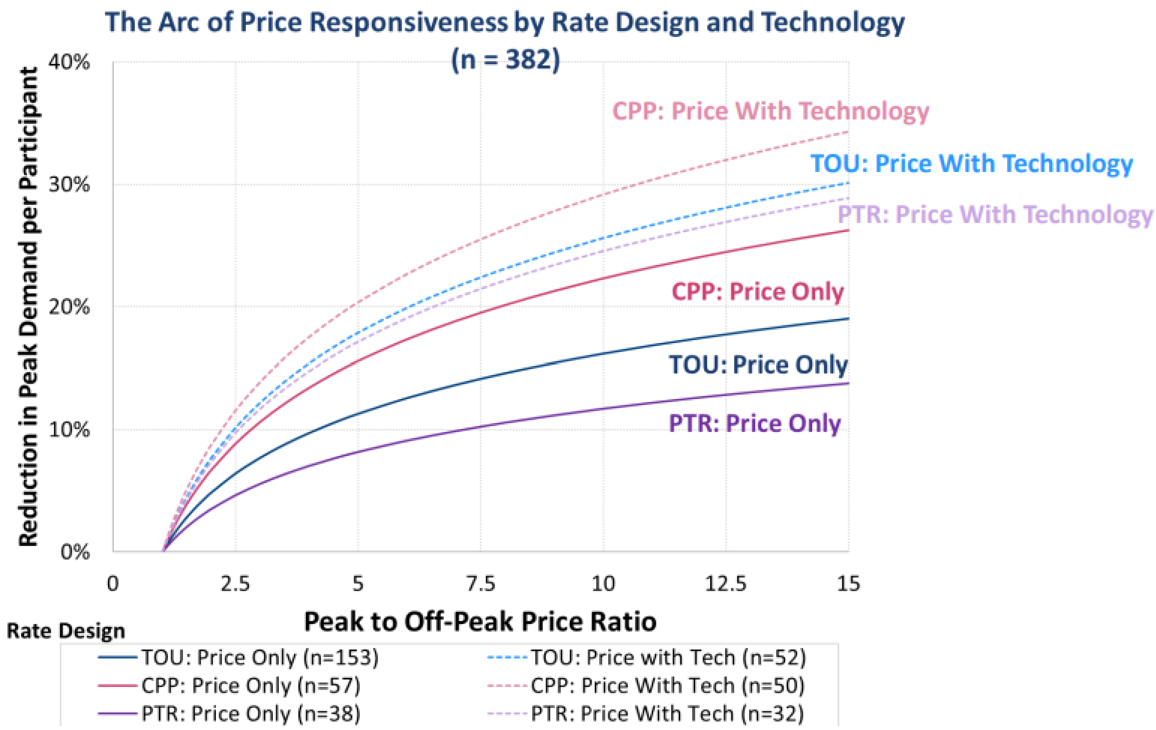
- ***Direct load control*** ("DLC") of different devices, appliances, and end uses – this may include smart thermostats, central or unitary heating, ventilation and air conditioning ("HVAC"), water heaters, pool pumps, electric vehicles ("EV"), or energy storage systems ("ESS"); DLC programs may have different delivery channels, including bring-your-own-device or direct install strategies; these may utilize enabling technologies such as smart appliances, embedded wifi, universal control modules, or switch-based device controls.
- ***Time-varying rates*** ("TVRs") and dynamic pricing options – these include time-of-use ("TOU") or real time pricing rates, and event-based price signals such as peak time rebate ("PTR") or critical peak pricing ("CPP") strategies; these can be designed for different customer segments and be technology specific, such as rates or incentives for EV owners to shift charging loads.
- ***Behavioral demand response*** ("BDR") – an event-based opt-out product that uses customer notification/messaging to encourage load shifting/shedding ***without*** the addition of an incentive.
- ***Curtailment Contracts or Interruptible Tariffs*** – typically focused on non-residential segments, these programs typically focus on firm curtailment through contractual arrangements; these can be established with customers directly through

utility programs or through demand response aggregators, which often work with national accounts and offer customization of curtailment strategies based on consumption patterns and industry type.

Specifically, time-varying rate options are well proven strategies used to achieve peak load savings reductions and provide opportunities for reducing energy burden through lowering energy bills. TOU rates in particular have been delivered successfully, delivered both as opt-in and opt-out or default rate structures, and have shown success with low to moderate income ("LMI") customers as well. A 2020 evaluation of several Maryland opt-in TOU pilots (with on-to-off peak pricing ratios of approximately 4:1 to 6:1) show summer on-peak reductions of 10-15% (2-7 p.m.) and winter from 5-6% (6-9 a.m.). LMI customers saved between 8-14% of summer peak, and customers realized bill reductions[44] up to 10%.[45] As another example, Fort Collins Utility introduced a default TOU rate in 2018 (with on-to-off peak ratio of approximately 3:1) and achieved 7.5% peak demand reduction at scale. They found that approximately 67% of customers achieved a bill reduction, with LMI customers savings in line with non-LMI.[46] Finally, Brattle provides some of the best research on time-varying rate analysis across a broad sample of programs (Figure 1), showing how savings achievements of TVRs vary by design and peak to off-peak pricing, and pairing with enabling technology (e.g., smart thermostats). This suggests that TVRs paired with technology approach 15-20% peak demand savings with peak to off-peak ratios between 3:1 to 5:1, which are perhaps among the most common TOU designs.

[44] Reducing LMI customer bills has an obvious benefit for PM6 and improving affordability.
[45] Brattle, PC44 Time of Use Pilots: Year One Evaluation (Sep. 15, 2020), https://www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf
[46] American Public Power Ass'n, Moving Ahead with Time of Use Rates, https://www.publicpower.org/system/files/documents/Moving-Ahead-Time-of-Use-Rates.pdf.

Figure 1. Arc of Price Responsiveness by Rate Design and Technology – Brattle 2023[47]



Specifically, TVRs such as TOU rates and dynamic pricing treatments require active customer participation to shift or reduce consumption during peak periods and thus, should meet ComEd's definition of eligible programs and activities that are allowed to contribute to peak demand reductions.

VII. Peak Load Reduction – Performance Metric Structure

Q. Please summarize ComEd's peak load reduction (PLR) performance metric.

A. ComEd has proposed a single PLR metric to reduce peak loads through demand response programs.[48] The metric will calculate the sum of actual peak load savings achievements (not capability) achieved through demand response programs across two categories. As

[47] Brattle, Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0 (Jan. 2023), https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf
[48] ComEd Ex. 1.01 at 12-14.

noted above, the first category (3A) includes peak savings from resources that are cleared resources with the PJM resource adequacy market. The second category (3B) includes resources "intended to reduce or shift usage away from peak times" but that are not cleared in the PJM resource adequacy market.[49]

Q. How does ComEd propose setting the baseline and calculating the achievement toward goals:

A. In ComEd Exhibit 1.01 (p.12-14) ComEd provides a description of the PLR performance metric, baseline, and its calculation.

ComEd has developed its PLR performance metric to measure incremental increases in savings from each previous year. In response to EDF 1.12, ComEd notes that "any existing peak load reduction from new initiatives would be accounted for in the baseline." With regard to programs eligible for PJM capacity this is based on cleared MWs at the start of each delivery year. For non-PJM eligible programs, ComEd proposes measuring savings using customer interval data to estimate actual load reductions based on enrolled capacity obligations compared to a baseline methodology.

The PLR performance metric is symmetrical, showing opportunities to both earn incentives (positive basis points) and incur penalties (negative basis points) based on their relative achievement of peak load.

Regarding a baseline for its PLR, ComEd has set a deadband of 0 MW incremental to its achieved savings from each prior year. The proposed PLR provides an opportunity to earn incentives for any load reduction greater than 0.1 MW (and penalties for any load reductions less than 0.1 MW) relative to each prior year's savings achievement. The

[49] ComEd Ex. 1.01 at 12-14.

maximum level of incentive and penalty is set at +/- 150 MW, which is associated with 6 basis points.

Q. Does ComEd explain the PLR performance incentive structure and how these savings achievements over baseline lead to earning performance incentives?

A. Yes, in ComEd Ex. 1.01, it provides the following table that shows the range of incentives and penalties relative to MW savings targets and their associated basis points.

	Penalties		Deadband	Incentives	
Metric range	-150 MW	-0.1 MW	0 MW	0.1 MW	+150 MW
Basis points	-6 bps	-0.01 bps	0 bps	+0.01 bps	+6 bps

Additionally, it provides an example of how the baseline is established for each year: "if ComEd achieved 200 MW in 2027, the baseline/deadband for 2028 would be 200 MW." Based on this example, to earn a maximum incentive of 6 basis points in 2028, ComEd would need to achieve peak load savings at or over 350 MW (baseline of 200 MW + incremental savings up to or over 150 MW).

Q. How many basis points are included for this PLR and how is that reflected in dollar terms?

A. As noted, ComEd can earn up to 6 basis points for its PLR performance metric. With regard to value of basis points in dollar terms, when asked in EDF 1.10 to provide the dollar value of the 6-basis points under the PLR, ComEd objected to this request, citing issues with required analysis, and that: "ComEd does not currently have an estimate of the dollar value of a 6-basis point incentive and penalty under the PLR metric for the period 2028-2031, because ComEd does not have an estimate of the rate base for the 2028-2031 period."

In lieu of this data from ComEd, as noted in section III above, I estimate a single basis point is approximately $865,000 based on a 2027 rate base of $17.3B and 50% equity component. While we can expect the rate base to increase in subsequent years, using this assumption results in an annual value of 6 basis points of $5,190,000. Over the 2028-2031 period, the value of the proposed maximum incentive/penalty is $20,760,000.

Q. Do you have any observations regarding ComEd's proposed PLR performance metric structure or goals?

A. Yes. While I agree with aspects of the proposed approach, there are several issues with this PLR proposal.

First, I appreciate that ComEd clearly shows the PLR metric relative to the proposed distribution of its savings goals and basis point earning potential. This transparency is important to show how savings achievements are tied to basis points. However, it is also important to provide more context for the value of these basis points, even based on an estimate regarding the current or forecasted rate base at this point in time.

Second, I agree with the proposed symmetrical structure of this PLR to include both incentive and penalties regarding achievement relative to PLR goals.

Third, I agree with ComEd's proposal to include separate categories of peak load associated with DR programs cleared in the PJM resource adequacy market and those that are not.

Fourth, while I appreciate the acknowledgement that performance targets should account for incremental savings beyond the prior year, the proposed rolling baseline reflecting prior achievements may be problematic and result in unintended consequences. As noted with regard to the affordability performance metric above, it is important not to reset the baseline based on prior year performance, which could reflect over- or under-performance based on a variety of factors. The baseline should be more directly connected with anticipated growth of eligible programs for a given year, with incentives awarded to performance that go above and beyond anticipated or status quo savings achievements.

Fifth, regarding the method for calculating each peak savings achievement, I agree that using actual achievements rather than planned capacity is appropriate. Regarding the method of estimating savings achievements for non-PJM programs, I also agree that using interval data analysis and developing a counterfactual baseline is appropriate to ensure rigorous evaluation of actual achievements on peak periods. More specifically, research designs for DR programs vary by program type, including various methods of experimental and quasi-experimental design, as well as data and model specification. This will be an important detail to clarify. For each non-PJM program, ComEd should clearly define a discrete research design and methodology for evaluating actual load impacts, along with the source for these values (e.g., third-party program evaluation). There should also be clarity with regard to the metric for summarizing peak savings, such as based on the highest saving hour or an average of the top 5 hours, similar to Ameren's proposed method for PLR calculation. Currently, this is unspecified in the PLR proposal.

Sixth, the proposed baseline (and associated performance targets) used to measure performance achievements and earn incentives appears disconnected from a discrete set of programs and anticipated annual growth of those programs. Regarding the baseline, ComEd's proposal is set at the peak load achievement from each prior year, with performance incentives based on incremental achievement beyond the prior year impacts. This does not account for any incremental and anticipated growth of existing programs or new programs ComEd may introduce within a given year. Performance incentives should reflect achievements beyond the status quo, involving proactive deployment and development of a demand response portfolio to go beyond the expected annual savings goals associated with all programs contributing to the PLR goal. Methods for scaling demand response programs include offering new or expanded products, developing opt-out or default program designs, and developing integrated deployment of DSM programs. Regarding the latter, integrated DSM approaches should help to increase adoption rates, improve cost effectiveness, and may include strategies like co-deployment of energy efficiency and demand response, co-enrollment in multiple demand response programs, and migration of customers from DR programs that provide higher value for ComEd and its customers (e.g., a PTR enrollee migrating to a smart thermostat program).

Seventh, based on ComEd's response to EDF 1.03 the forecast of load reduction capability in 2027 is approximately 211 MW or 0.9% of 2023 system peak (22,468 MW).[50] Currently, ComEd's 2025 DR reductions (110 MW), are approximately 0.5% of the 2023 system peak load.[51] ComEd's proposed levels represent a relatively minor increase, and are low in comparison to other utilities with demand response portfolios.

Q. Do you agree with ComEd's proposed approach for developing its PLR baseline?

A. No, there are several issues with this proposed approach.

While we appreciate the intention underlying ComEd's proposal to build in an adjustment to its baseline based on incremental increase from the prior year, the proposed approach does not align itself with either a changing set of discrete programs that could inform these goals nor a forecast of achievable potential or program enrollments expected within a given year. It being set at the prior year leaves open the potential of under- or over-performance

[50] CUB-EDF Ex. 1.02.
[51] PJM Load Forecast Report (Jan. 2024), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.ashx

in a given year to shift the baseline that may unintentionally impact the outcome of performance incentive achievement for the next year. For example, if ComEd developed 200 MW of load reduction capability in a given year but, due to technical issues, was only able to dispatch 30 MW, the next year baseline would be set at 30 MW; at which point, under the current PLR proposal, ComEd would not require developing any additional DR programs and could call its 200 MW and achieve all 6 basis points (i.e., 30 baseline + 180 MW = 200 MW, over the 150 MW target).

Furthermore, ComEd assumed a projection of incremental growth of its existing programs around 50 MW in total over the next few years (as shown in CUB-EDF Ex. 1.02, EDF 1.03_Attach 1), it appears the incentive would be driven (at least in part) by the expected annual growth of these existing programs, rather than setting an incentive that rewards incremental performance beyond the status quo. Performance incentives should reflect substantial achievements in service to and/or beyond annual savings goals across all programs contributing to the PLR goal, thus meriting an incentive, rather than a business-as-usual scenario.

Q. Based on these issues, do you have suggestions for how a PLR baseline could be restructured?

A. In sum, the baseline should be dynamically aligned with program offerings within a given year, including any incremental achievements of DR capacity from the prior years, forecasted for all programs ComEd anticipates contributing to its PLR at the time. As new programs are introduced, the PLR goal should account for anticipated capacity achievements through each new offering. Ideally, this will be informed by a demand response potential assessment and subsequent program planning and design processes.

These will allow ComEd to identify cost-effective programmatic opportunities and develop estimates of annual program-specific savings targets for a comprehensive suite of cost-effective DR programs. It should be the annual estimates of program-specific savings potential that can be used to inform the PLR performance metric baseline, which should then be scaled based on the incremental annual savings for the discrete set of programs. The proposed PLR metric should incentivize a grid plan that reflects new programs or increased deployment of existing programs over the performance period.

Q. Are there implications that could result in a misalignment between establishing an annual savings target for PLR and ComEd's opportunity to achieve a performance incentive?

A. Yes, in part. While ComEd has proposed a baseline that is incremental to any eligible MW reductions from the prior year, the proposed PLR still reflects a disconnection between the existing programs and any new programs, and associated achievements expected from each of those programs. Under this current condition, it means that in any given year that ComEd introduces a new program or increases participation of existing programs, any of this incremental growth yielding impacts greater than the prior year (which I would expect, save for program attrition) will be eligible for the performance incentive. As noted, the PLR should be dynamic and effectively calibrated based on the specific programs ComEd is deploying in service to achieve peak load reductions. The baseline should also account for anticipated growth of new and existing programs for a given year.

Furthermore, these targets should be directly associated with expected achievements from each of the individual programs. A potential assessment (and the subsequent program planning and design processes), should include planning assumptions reflecting per unit savings potential and adoption rates to estimate each year's peak demand savings.

One implication of not aligning the PLR with existing programs is that some programs and program designs are easily scalable and ComEd could exceed its PLR goal with a single avenue, rather than working to grow peak savings potential across the full range of DR opportunities.

For example, redesigning ComEd's peak time rebate (PTR) program to enhance adoption rates could scale DR savings dramatically within a single year. Assuming an average savings per participant of 0.08 kW to 0.13 kW and a 90% participation rate of all residential customers (both assumptions are consistent with other evaluations and planning studies), ComEd could achieve approximately 269-437 MW (243-395 MW above current program design).[52] The lower bound of this increase in savings is more than four times the 2024 load reduction savings (from CUB-EDF Ex. 1.02 EDF 1.03_Attach 1). It would also easily surpass ComEd's proposed goal for achieving its full annual PLR incentive. This could reduce ComEd's effort to achieve capacity savings in other programs or sectors where further potential savings are attainable. While I am not a lawyer, I understand that there may be barriers to running opt-out designs in Illinois; in this particular case, PTR offerings have no downside risk to customers, providing equal opportunity for customers to participate, without penalties or requirement of specific equipment or technology.

The current PLR structure may also incentivize a strategy to sequence annual program rollout to achieve the maximum incentive (up to 150 MW, as proposed), but then could

[52] Xcel Energy Colorado Demand Response Study: Opportunities in 2030, https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf.; Interim Evaluation Report of the Smart Grid Test Bed Project: Phase 1: July 2019-October 2020 (submitted Jan. 26, 2021), https://edocs.puc.state.or.us/efdocs/HAD/um1976had164616.pdf; *See also*, CUB-EDF Ex. 1.06.

penalize ComEd from maintaining a portfolio as it approaches the upper end of an adoption curve for a given product. Ideally a performance incentive is in place that encourages ComEd to develop, maintain, and dispatch a DR portfolio once it has reached an anticipated level of achievable potential savings.

Q. Are there any additional issues related to the disconnect between the performance goal relative to its baseline and program delivery?

A. Yes. Performance-based incentives should not be awarded for achieving targets that are status quo. Utilities should be incentivized for exceeding baseline expectations, and it is rational to include some level of improvement within the baseline. ComEd has a current portfolio, as of 2024, that is approximately 59 MW and approaching 0.26% of its system peak load, which would be reflected in an incremental baseline for performance incentives. As shown in CUB-EDF Ex. 1.02 (EDF 1.03_Attach 1), it anticipates 50 MW incremental MW a year, which is approximately one third of the proposed target (at 150 MW) to earn the maximum basis points. As such, establishing a baseline that does not account for this anticipated growth seems counter to the theoretical underpinning of performance incentives. The proposal effectively provides ComEd 33% of the performance incentive for achieving baseline expectations, through anticipated increased enrollment in its existing programs. Even then, the proposed PLR savings, as a percentage relative to peak load (0.26%), are much lower than other utilities developing similar DR portfolios.

Q. Are you recommending a new target for ComEd's PLR

A. Because ComEd has not conducted a recent potential study to inform their proposed PLR targets, we propose a revision to its current proposal in the interim that will better reflect the current and future peak load savings potential of ComEd's DR programs. As noted, the

DR savings potential from its current programs at 59 MW, and at 0.26% of its 2024 system peak, is relatively low by comparison. The performance target should be set at a higher level to encourage additional development of DR resources over the next three years prior to the 2028-2031 period when the PLR goes into effect.

I recommend the Commission direct ComEd to set a baseline that reflects a peak savings total as a percentage of system peak load. To set this baseline, ideally I would use the achievable savings potential from a demand response potential assessment to reflect the total suite of DR opportunities available, including adoption rates and estimates of savings by individual sectors and programs. I would also want the baseline to be dynamic and reflect the anticipated achievements of a discrete set of active and existing DR program offerings (and their associated targets) within a given year.

To provide context on setting this target, in lieu of an existing study, we can look at achievements of other utilities that have developed demand response portfolios and the percentage of system peak load that has been achieved. While some utilities have achieved up to 10-20% of system peak through DR programs, 3-10% may be more reasonable for ComEd in the near term. A few examples include:

- MidAmerican (Iowa) – 7% peak load: 355 MW of peak demand savings (2023, EIA 861) compared to 5,037 MW system peak (2023)[53]
- Portland General Electric (Oregon) – 3% peak load: 146 MW compared to 4,498 MW system peak.[54]

[53] EIA-861 Annual Electric Power Industry Report (2023); MidAmerican Energy Co., Resource Evaluation Study Report (Nov. 1, 2024), https://www.midamericanenergy.com/media/pdf/mec_resource_evaluation_study_11-1.pdf.
[54] EIA-861 Annual Electric Power Industry Report (2023); Portland General Electric, Earnings Conf. Call (Third Quarter 2023), https://investors.portlandgeneral.com/static-files/e5c30475-a2d9-40cb-8ae6-58900384907e.

- Consolidated Edison (New York) – 3.4% peak load: 407 MW (2023, EIA 861) compared to 11,822 MW system peak (2024).[55]
- Baltimore Gas and Electric (Maryland) – 5% peak load: 342 MW (2023, EIA 861) compared to 6,406 MW system peak (2023).[56]
- Potomac Electric Power Company (Maryland) – 4% peak load: 217 MW (2023, EIA 861) compared to 5,872 MW system peak (2023). [57]
- Xcel (Colorado) – 9% peak load: 664 MW compared to 7,086 MW system peak.[58]
- Fort Collins Public Utilities (Colorado) – 7.5% peak load reduction achieved through a default time of use rate.[59]

Assuming a conservative percentage of 3% of ComEd's 2023 system peak (22,468 MW), results in a peak demand savings target of 674 MW.[60] As noted, the current 2024 load reduction capability, which would serve as the 2025 baseline, is 59 MW, equivalent to approximately 0.26% of 2024 system peak, and is well below levels of achievable peak savings compared to other utilities that have begun developing a suite of flexible load resources.

I suggest setting the PLR target based on a percentage of the system peak, currently based on 2023 pending any more recent available data. Based on achievement in other utilities, I suggest setting 2028 at 1%, 2029 at 2%, 2030 at 3%, and 2031 at 4%. A 1% of the 2023

[55] EIA-861 Annual Electric Power Industry Report (2023); Con Edison Invests in Infrastructure to Meet Increased Summer Energy Demand | Con Edison
[56] EIA-861 Annual Electric Power Industry Report (2023); https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.ashx.
[57] *Ibid.*
[58] *Ibid.*; Xcel Energy Colorado Demand Response Study: Opportunities in 2030; https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf.
[59] American Public Power Ass'n, Moving Ahead with Time of Use Rates, https://www.publicpower.org/system/files/documents/Moving-Ahead-Time-of-Use-Rates.pdf.
[60] PJM Load Forecast Report (Jan. 2024), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.ashx 2024-load-report.ashx

system peak target reflects approximately 225 MW. As ComEd's forecast for its current programs is set at 211 MW for 2027, and by carrying forward its assumed 50 MW of incremental capacity to increase this total to 261 MW for 2028, one can assume ComEd is on a path to exceed this target. Additionally, given three years for development of existing and new program offerings, this provides sufficient opportunity to meet and exceed targets to earn a performance incentive.

Additionally, ComEd did conduct a potential assessment of demand response in 2009, which identified an achievable potential of 940 MW by 2016, reflecting 4% of system peak load.[61] Table 2 provides the achievable potential for demand response resources by sector anticipated for achievement by 2016.

Table 2. ComEd Demand Response Potential Assessment (2009) – Achievable DR Potential by Sector

Sector	Sector Peak	Technical Potential	Achievable Technical Potential	Achievable Technical Potential As Percent of Sector Peak
Residential	10,988	9,886	342	3%
Commercial	11,444	3,422	563	5%
Industrial	2,678	1,609	274	10%
Total	**25,110**	**14,917**	**940**	**4%**

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs have not been taken into account.

Q. Do you believe these savings are achievable?

A. Yes, for several reasons. First, there is currently over three years for ComEd to both (1) conduct a DR potential assessment and/or (2) further develop a suite of programs to achieve these savings. There is not only the opportunity to scale its existing programs but also to develop additional demand response products, including time-varying rates. Additionally, there are opt-out program designs for rates and behavioral demand response

[61] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-c-1---comed-potential-study.pdf

that can be effectively used to scale achievement of peak load savings. As shown in the increasing participation in a PTR example, it would be easy for ComEd to exceed this 1% target by achieving higher PTR adoption, TVR options, or a variety of other DR resources. Second, if as I recommend, ComEd has conducted a potential assessment and program planning for a suite of programs, there may be an opportunity to update the PLR to reflect the projected achievements associated with only those programs offered by ComEd within a given year. This true up, linking the annual goals with current program activity, will create consistency between delivery and achievement, rather than setting a target that is not reflective of its current or anticipated peak load capability for a given year. The 2009 potential assessment referenced above also indicates that 4% of peak is achievable; while program strategies have changed, this is a good indicator that at minimum 4% of its system peak is achievable.

Third, as shown above, we can expect sufficient headroom for ComEd to grow these resources based on the achievements of other utility's demand response portfolios. In considering peak demand savings as a percentage of system peak load, other utilities are achieving 3-9% or more, with ComEd currently at approximately 0.26% of its 2023 system peak.

Finally, in response to EDF 1.05, ComEd reports that it "does not currently employ strategies to co-deploy energy efficiency and demand response." Co-deployment of EE/DR resources provides significant opportunity to increase customer adoption rates of DR programs, reduce costs, and help foster a more integrated DSM portfolio. Co-deployment refers to the ability to leverage existing products, programs, and systems that encourage a combined deployment of resources, yielding benefits of measure interactivity and achieving more cost-effective delivery. To do this effectively, ComEd would need to develop a deliberate strategy by each DSM program. For example, pre-enrollment strategies include linking enrollment in a DR program at the point of purchase for efficiency equipment, such as receiving an offer and enrolling in a smart thermostat DR program when purchasing the thermostat at a store or online marketplace. DR service provider, Uplight, indicates that this type of enrollment strategy increased adoption rates in DR programs from 10-20% up to 60-80%.[62] Another example of co-deployment can occur through other DSM delivery models. For example, in 2018 United Illuminating (UI) delivered a pilot through its low-income retrofit program that installed heat pump water heaters and recruited customers into a DLC program, yielding a 90% enrollment rate.[63] Other interactions between smart thermostats and TOU rates show that enabling devices can increase customer savings potential by 10%. These types of interactions between DSM products have the potential to increase both per unit savings and the adoption rates of DR products. As ComEd reports having not pursued any strategies for co-deployment, this seems like an untapped resource that could further develop, scale, and deepen savings through its DR programs.

Q. Do you have any recommended changes to ComEd's proposed incentive structure?

A. No, I propose maintaining the same incentive structure and distribution ComEd has outlined to earn up to 6 basis points, however I propose translating this into percentage terms to apply to the proposed interim baseline savings targets described above. Below, I have adapted the symmetrical performance incentive structure originally proposed by

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[62] https://uplight.com/wp-content/uploads/2021/06/U_eBook_DRPE_ExperienceAndGridFlexibility-1.pdf.
[63] https://www.aceee.org/sites/default/files/pdf/conferences/hwf/2019/7d-rodrigues.pdf

ComEd for the application of the interim savings targets based on percentage savings, as proposed in ComEd Ex. 1.01.[64]

Table 3 shows the distribution of incentive earning potential proposed by ComEd applied to the my recommendation of proposed annual baselines for 2028 through 2031 (i.e., 1-4% savings of system peak). Table 4 provides the same information, and translates the savings percentage of peak load into MW values based on the 2023 system peak. As shown, the revised recommended baselines range from 1% to 4% of system peak load and reflect an increase of peak load savings potential from 225 MW to 889 MW. For example, looking at 2028, ComEd could earn all 6 basis points by exceeding 100% (or 449 MW) of the 2028 baseline target (at 1% savings of system peak, or 225 MW), or else could pay penalties of negative basis points for achievements of less than 1% of system peak.

Table 3. Proposed PLR Savings Targets and Incentive Structure (%) – using a Percentage of the System Peak (2023)[65]

Basis Points	Distribution of Goal Relative to Baseline	Proposed Interim Annual PLR Targets and Incentive Structure: Peak Pct Savings (%)			
		2028	2029	2030	2031
-6	-100%	0.0%	0.0%	0.0%	0.0%
-3	-50%	0.5%	1.0%	1.5%	2.0%
-1	-17%	0.8%	1.7%	2.5%	3.3%
-0.01	-0.2%	0.998%	1.997%	2.995%	3.993%
0	0%	1.0%	2.0%	3.0%	4.0%
0.01	0.2%	1.002%	2.003%	3.005%	4.007%
1	17%	1.2%	2.3%	3.5%	4.7%
3	50%	1.5%	3.0%	4.5%	6.0%
6	100%	2.0%	4.0%	6.0%	8.0%

[64] CUB-EDF Ex. 1.06.
[65] Ameren Proposed Performance Metrics, https://icc.illinois.gov/api/web-management/documents/downloads/public/Ameren%20Illinois%20Performance%20Metric%20Proposal%202028%20-%202031.pdf.

Table 4. Proposed PLR Savings Targets and Incentive Structure (MW) – using Savings as Percentage of the System Peak (2023)

Basis Points	Distribution of Goal Relative to Baseline	Proposed Interim Annual Targets and Incentive Structure: Savings as Pct of 2023 System Peak (MW)			
		2028	2029	2030	2031
-6	100%	0	0	0	0
-3	50%	112	225	337	449
-1	17%	187	374	562	749
-0.01	0.17%	224.3	448.6	673	897
0	0%	224.7	449	674	899
0.01	0.17%	225.1	450	675	900
1	17%	262	524	786	1,049
3	50%	337	674	1,011	1,348
6	100%	449	899	1,348	1,797

VIII. Peak Load Reduction – ComEd DR Programs

Q. What DSM or DER programs are currently being offered by ComEd, and of those, which have the potential to contribute to peak savings?

A. ComEd provided EDF 1.03_Attach 1, CUB-EDF Ex. 1.02, including a table with six DR products, either currently being offered or being developed. Table 5 provides a list of these programs and the annual projected load reduction capability by program for 2023 through 2027. These programs include Peak Time Savings ("PTS"); AC Cycling; Hourly Pricing; Mandatory Load Response ("MLR"); Virtual Power Plant ("VPP"), which includes smart thermostat and behind-the-meter battery direct load control components; and Community Solar and Storage ("CS+S").

Table 5. List of DR Programs and Projected Load Reduction Capability, 2023-2027

	2023	2024	2025	2026	2027
PTS, MW	24.4	23.2	24.3	24.3	24.3
AC Cycling, MW	35.9	35.3	34.6	33.9	33.2
Hourly, MW	0.5	0.5	0.6	0.7	0.7
Mix of MLR, VPP, and CS+S (proposed), MW	n/a	0.0	51.0	102.0	153.0
New Stack Programs selected by 2024 RFI (proposed), MW	n/a	n/a	n/a	n/a	n/a
Total Projected Load Reduction Capability, MW	60.8	59.1	110.5	160.8	211.2
Total Projected Incremental Load Reduction Capability	n/a	-1.8	51	50	50

Q. Do you have any observations based on the list of programs ComEd has indicated are either current or under consideration and intended to count toward the PLR performance incentive?

A. Yes, I have several. First, based on the programs listed, only the line item including a mix of three programs (MLK, VPP, and CS+S) shows substantive incremental growth over time (and beginning in 2025). PTS, AC Cycling, and Hourly programs do not show any significant growth, suggesting that ComEd may not anticipate new customer enrollments or may not be actively working to market or grow these resources. In particular, its PTR program (PTS) is shown to be static at approximately 9% of ComEd residential customers (assuming this is only residential). As a point of comparison, Portland General Electric has 123,789 participants in its PTR program as of 2023, which represents 15% of customers; it anticipates approximately 2% increase by 2026.

Second, while this list includes several different types of DR products (PTR, HVAC DLC, Battery DLC, non-residential curtailment), it appears limited in terms of a full portfolio of programmatic options for achieving peak load savings. As noted, time-varying rates, such as TOU or time-of-day rates, have significant opportunity to achieve persistent savings during peak periods through customer action, including both load shifting and conservation behavior. DLC-style programs are also common for other technologies, including for storage and EVs (noted as under consideration by ComEd), but also other end use equipment such as water heaters, pool pumps, and other types of HVAC (unitary cooling and heating).

Third, the Commission recently approved opt-in Time of Use ("TOU") rate designs for ComEd.[66] This recently approved TOU rate should be considered in the baseline and considered part of the program efforts for PLR if it is expanded beyond its assumed adoption levels.

Finally, non-residential customers typically have several options for participating in demand response, which often vary based on customer segment (e.g., small/medium commercial vs. large commercial and industrial customers). Other DR options for small/medium commercial customers may be like those offered for residential (e.g., TOU, PTR, DLC), while offerings for non-residential include load curtailment or interruptible rates, either through utility-led programs, directly through wholesale markets under PJM, or through third-party aggregators. Regarding the latter, aggregation firms work in numerous jurisdictions to develop capacity resources for both wholesale and retail applications, often achieving economies of scale by aggregating smaller C&I customers that do not qualify for larger curtailment contracts, working with national accounts, and through developing customized curtailment strategies based on site-specific factors. As shown, ComEd is only counting peak savings for one non-residential program toward its PLR. Based on information provided in CUB-EDF Ex. 1.02 (EDF 1.03_Attach 1), it is

[66] Final Order on Rehearing, ICC Dkt. No. 24-0378 (June 17, 2025).

unclear which customer segments of non-residential customers are eligible to participate in the programs listed.

Q. Has ComEd conducted a recent demand response potential assessment that would evaluate achievable peak demand savings potential for a comprehensive suite of products?

A. It does not appear so. Data request EDF 1.01 asked the following: "Provide all estimates of achievable potential, adoption forecasts, and expected MW savings related to DR or other DSM programs that have been developed by the Company for any program years from 2025 through 2030. Include any relevant reports, spreadsheets, or modeling documents." In response, ComEd did not provide any potential study report, but instead, pointed to a DSM program forecast for PLR performance metric in its Refiled Grid Plan, and included the workpaper attachment CUB-EDF Ex. 1.02 (EDF 1.03_Attach 1) supporting that forecast. As noted above, ComEd sponsored a demand response potential study in 2009 and it identified an achievable potential of 940 MW (or 4% of system peak load) achievable by 2016. [67]

Q. In your opinion, is the forecast included in CUB-EDF Ex. 1.02, EDF 1.03_Attach 1, a suitable proxy for a demand response potential assessment?

A. No, it is not. The referenced workpaper does not create a comprehensive assessment of all available resources within ComEd territory across various sectors and customer segments that can contribute to load flexibility and peak demand savings. In particular, it would be helpful to understand and differentiate DR potential associated with various sectors and

[67] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-c-1---comed-potential-study.pdf

segments within ComEd territory, including products that are applicable for customers that are receiving supply services through ComEd compared to other ARES.

A few examples of recent DR potential studies provide a more comprehensive assessment of strategies across sectors, segments, and end uses to more fully evaluate this resource potential. Table 6 and Table 7 provide snapshots from recent studies of demand response savings potential by product for Xcel in Colorado and Puget Sound Energy (PSE), respectively. The Xcel study differentiated types of potential by the frequency a resource could be called, with low-frequency programs reflecting event-based programs up to 75 hours a year, while high-frequency programs reflect persistent peak reductions based on savings or shifting occurring over 75 hours a year.

Table 6. Xcel CO DR Potential Study (2021) – List of Products and Savings[68]

Program	Class	Existing (2021)	Planned change in ERP (2030)	Incremental Achievable Potential (2030)	Total Achievable Potential (2030)
Low-frequency programs (<75 DR hrs/yr)					
Savers Switch	Residential	214	-26	0	188
Smart thermostat	Residential	25	8	176	209
Peak time rebate	Residential	0	0	123	123
Behavioral DR	Residential	0	0	0	0
BTM storage	Residential	1	0	42	43
Smart thermostat	Small C&I	1	3	0	4
Peak time rebate	Small C&I	0	0	0	0
Interruptible	Large C&I	194	-25	17	186
CPP	Large C&I	27	23	0	50
Peak Partner Rewards	Large C&I	12	32	0	45
EV Workplace Managed Charging	N/A	0	1	2	4
Peak Day Partners	Large C&I	22	14	0	36
Low Frequency Total		**496**	**31**	**362**	**889**
High-frequency programs (>75 DR hrs/yr)					
Default TOU	Residential	0	0	126	126
GIWH	Residential	0	0	27	27
EV TOU (Home)	Residential	0	0	67	67
Default TOU	Small C&I	0	0	0	0
Default TOU	Large C&I	0	0	27	27
Auto DR HVAC/AC	Small C&I	0	0	16	16
Auto DR HVAC/AC	Large C&I	0	0	9	9
Auto DR Lighting	Small C&I	0	0	9	9
Auto DR Lighting	Large C&I	0	0	5	5
High Frequency Total		**0**	**0**	**285**	**285**
Portfolio Grand Total		**496**	**31**	**647**	**1,174**

[68] Xcel Energy Colorado Demand Response Study: Opportunities in 2030

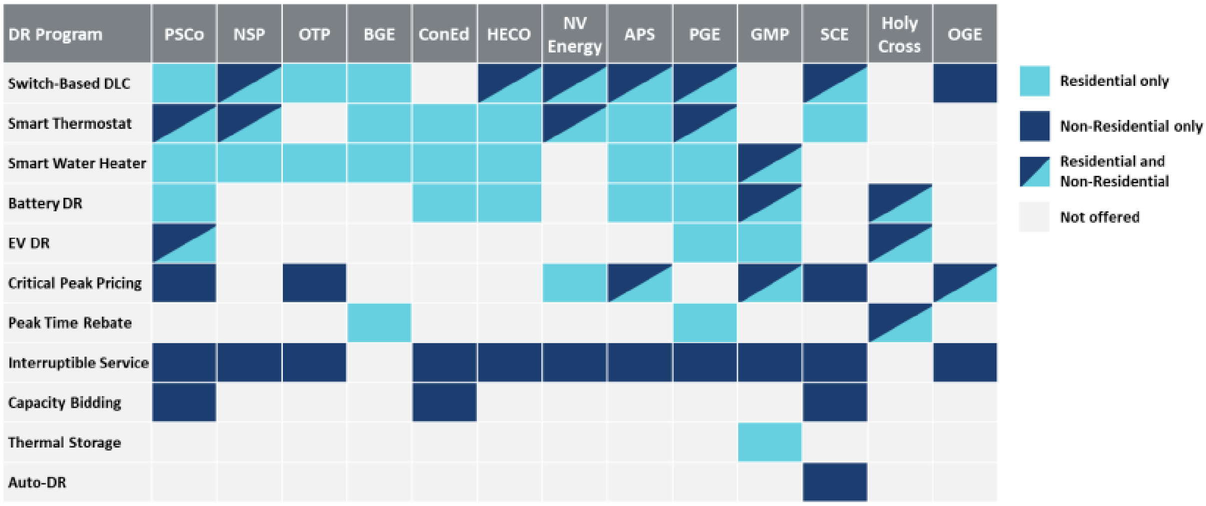
Table 7. PSE DR Potential Study (2024) – List of Products and Savings[69]

Product	Winter Achievable Technical Potential (MW)	Percentage of PSE System Peak (Winter)	Summer Achievable Technical Potential (MW)	Percentage of PSE System Peak (Summer)
Residential Electric Resistance Water Heater (ERWH) DLC Switch	0	0.00%	0	0.00%
Residential ERWH DLC Grid-Enabled	32	0.52%	22	0.39%
Residential HPWH DLC Switch	0	0.00%	0	0.00%
Residential HPWH DLC Grid-Enabled	58	0.94%	29	0.53%
Residential HVAC DLC Switch	97	1.56%	50	0.90%
Residential Bring Your Own Thermostat (BYOT) DLC	108	1.74%	100	1.81%
Residential EVSE DLC Switch	42	0.67%	42	0.75%
Medium Commercial HVAC DLC Switch	18	0.30%	77	1.40%
Small Commercial HVAC DLC Switch	3	0.04%	5	0.10%
Small Commercial BYOT DLC	3	0.05%	4	0.07%
Commercial Curtailment	16	0.26%	20	0.36%
Industrial Curtailment	5	0.08%	5	0.09%
Residential Critical Peak Pricing	33	0.54%	74	1.35%
Commercial Critical Peak Pricing	21	0.34%	26	0.48%
Industrial Critical Peak Pricing	2	0.02%	2	0.03%
Total	**439**	**7.05%**	**455**	**8.24%**

The Xcel Potential study also provides a summary of DR program offerings from a selection of utilities, highlighting a range of different DR programs (as of 2021) being deployed by more than a dozen utilities from around the country (shown in Figure 2 below). Note, this list of DR programs includes a variety of strategies, including traditional DLC, dynamic rates, and load reduction associated with EV and storage.

[69] PSE 2023 Electric Progress Report: Conservation Potential and Demand Response Assessments – Appendix E

Figure 2. Matrix of DR Program Offerings (Xcel Potential Study, 2021)



Notes: Based on Brattle review of utility websites and tariffs. NSP = Northern States Power, OTP = Otter Tail Power, BGE = Baltimore Gas & Electric, HECO = Hawaiian Electric Company, APS = Arizona Public Service, PGE = Portland General Electric, GMP = Green Mountain Power, SCE = Southern California Edison, OGE = Oklahoma Gas & Electric.

Q. In your opinion, what types of programs or initiatives should contribute to peak load reduction?

A. In my opinion, ComEd can and should be incentivized to develop a portfolio of resources to optimize demand flexibility capability that can best serve peak issues, both on a system level (e.g., generation) and a local level (e.g., distribution). The performance incentive should reflect programs toward the goal of utility interventions that support cultivating this flex load resource. As shown, there are a wide variety of initiatives that can support peak demand, as well as various definitions for categories of resources, like “demand response.” There are a broad set of strategies that achieve demand flexibility under the framework of “demand response”, including DLC (for appliances and end use loads) and time-varying rates and dynamic pricing products, like TOU, PTR, and CPP. I also believe that these strategies used to control devices and encourage customers to shift or reduce loads are applicable to a broadening scope of applications, including EVs and energy storage systems.

In practice, there should be full transparency regarding all eligible products that can contribute to the PLR. The utility should be proactive and explicit about each program contributing toward peak loads and its PLR. This may require additional guidance if there is a lack of clarity regarding products that are eligible or ineligible to contribute toward the PLR.

I also agree that a utility should earn a performance incentive for the demonstrated achievement of this peak load reduction, rather than purely based on capability. This should reflect a full-scope of any interventions that provide the utility with the capability of demand reduction and broader flexibility relative to peak loads.

Q. Do you have a recommendation regarding specific programs, initiatives, or technologies eligible for contributing toward the PLR performance metric?

A. There appears to be the need for clarification on the definition of eligible DR products that can be counted toward the PLR. I recommend the Commission and stakeholders consider how best to establish this definition and eligible resources to incentivize the development of a holistic portfolio of resources in service toward greater demand flexibility. We want to be mindful to take a holistic view of growing a flexible load resource portfolio and not limit products that can be used toward these ends, while also avoiding double counting of impacts. At a minimum, this should include rate options like TOU, more options for non-residential customers, and more opportunities for customer segments to participate in multiple programs to increase potential for demand flexibility through these resources.

IX. Peak Load Reduction – Tracking Metrics

Q. Please summarize current tracking metrics related to PLR proposed by ComEd?

A. In ComEd Exhibit 1.01 (p.22-23), ComEd outlines a suite of tracking metrics related to six categories: Emissions Reduction, Grid Flexibility, Cost Savings, Diversity in Jobs and Opportunities, Equity in Allocation of Grid Planning Benefits, and Other. Metrics associated with the development and performance of resources contributing to peak savings and demand flexibility are primarily included within its Emissions Reduction, including 11 components related to #5 (Any Demand Response-Related Tariff or Program, p.26-28), and Grid Flexibility metrics, including 16 related to #15 (Grid Flexibility, p.32-35).

Q. Do you have any observations regarding the current tracking metrics related to PLR?

A. Yes, this is a good start. I appreciate that many of these metrics are structured for consistency across all programs offering peak savings and demand flexibility, rather than being overly specific to a single or existing suite of programs. This provides flexibility for ComEd to develop new programs contributing to peak load reduction and consistently report on the same set of relevant metrics as existing programs. There are some additional metrics that will be valuable to include, to support tracking progress regarding participation and performance.

Q. Are there any additional tracking metrics related to peak load impacts or performance of demand response resources that would be helpful for ComEd to track?

A. Yes, there are some additional metrics that will be important regarding performance improvements related to the achievement of peak loads, involving customer experience, retention, engagement, and per unit savings. Additionally, there are several metrics that will be important as ComEd grows its DR portfolio and encourages adoption of multiple flex load offerings and co-deployment of DSM offerings. Finally, there should be consistency in tracking these metrics for all programs that provide peak load savings and contribute to its PLR. Here is a list of some additional TMs that are cross-cutting and applicable across different DR and DER programs. Some of these overlap with existing TMs proposed by ComEd in part. I recommend ComEd consider these to integrate and develop a comprehensive and consistent list of TMs to track these details for each of its DR and DER programs:

- ***Incremental and Cumulative Customer Enrollments*** – # of customer enrollments in DR/DER programs within a given year, both incremental, and the cumulative total participation as of a specific date (e.g., January 1). Note, TM #15 lists several components specific to individual program offerings (e.g., Peak Time Rebates, Pricing programs) – I suggest considering a single set of metrics that can consistently be used across any new or existing program.
- ***Incremental and Cumulative Enrolled Capacity*** – both the incremental increase and cumulative total of enrollment capacity savings potential (in MWs) for all DR/DER programs within a given year. Note, similarly, TM #15 includes separate components that are specific to programs or technologies (e.g., total estimated capacity of customer-sited energy storage systems in programs). ComEd has proposed several separate programs with energy storage under its VPP and CS+S – similar to the prior comment, I suggest tracking this metric across all programs, rather than listing it as a technology-specific metric.
- ***Peak Load Savings Capacity as a Percentage of Seasonal System Peak Loads*** – % of enrolled peak savings capability of each DR/DER program individually and as a cumulative total relative to the seasonal system peak for a given year.
- ***Customer attrition*** – # of customers participating in DR programs (and percent of total participants) that un-enroll from a program within a given year.
- ***Customer migration*** – # of customers enrolled in one DR program that un-enroll to participate in another DR program (e.g., customer leaves PTR to enroll in DLC).
- ***DR co-enrollment*** – number of customers that participate in more than one DR program, by program/tariff.

- ***EE/DR co-deployment*** – number of customers that enrolled in a DR program through enrollment channels available via EE offering within a given year, by program/tariff.
- ***Deployment of enablement devices*** – count of equipment/devices delivered through EE that will increase opportunities for enrollment in DR (e.g., smart thermostats, grid-enabled equipment).
- ***Interconnection Timeline*** – for any resources requiring interconnection, such as EV, solar, or storage projects, track the timeline (in days) between project application to energization. Inclusion as a PLR tracking metric would not replace any performance metric related to interconnection timelines.
- ***Event participation*** – # of enrolled customers that actively opt-out of participation for a given event (e.g., actively override DR controls), tracked by program and event date/time/temp.
- ***Participation by demographic criteria. Income Qualified, >65 yrs, and EEIC communities*** – such as # and percent of total customers enrolled in DR programs/tariffs based on income eligibility, age (>65 years), and EEIC communities (based on designated ZIP code or census areas).
- ***Participation by geographic criteria related to grid-constraints*** – # and pct of total customers enrolled in DR programs/tariffs within a geography (e.g., circuit/substation boundary, ZIP code, Census area) flagged as having risk of grid constraints, such that demand flexibility could benefit localized distribution peaks.

X. Conclusion

Q. Do you have any concluding comments?

A. Yes, the electric grid is an important backbone for Illinois' economy. The performance metrics for the multi-year grid plan impact the design and delivery of important and sizable investments on behalf of ratepayers. On behalf of the CUB-EDF and Energy Futures Group, I appreciate the opportunity to submit this testimony on this important matter.

I request that comments and recommendations provided herein do not preclude the ability to include additional comments on performance metric levels in the forthcoming grid plan filings.

Q. **Does this conclude your testimony?**

A. Yes.