STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act	)))	Docket No. 22-0067
COMMONWEALTH EDISON COMPANY	))	

DIRECT TESTIMONY OF
WILLIAM D. KENWORTHY

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER
AND
VOTE SOLAR

April 6, 2022

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I. WITNESS IDENTIFICATION

Q: Please state your name and business address.

A: My name is William D. Kenworthy. My business address is 1 South Dearborn Street, 20th Floor, Chicago, Illinois 60603.

Q: By whom are you employed and in what capacity?

A: I serve as Regulatory Director, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 3,900 members in Illinois. Vote Solar is not a trade organization nor does it have corporate members.

Q: On whose behalf are you submitting this direct testimony?

A: I appear here in my capacity as an expert witness on behalf of the Environmental Law & Policy Center and Vote Solar.

Q: Please summarize your qualifications, experience, and education.

A: I have nearly 30 years of experience in the energy industry in both the public and private sectors working in the renewable energy business and in energy policy. Of that experience, I spent eight years in solar energy project development working primarily on commercial and industrial distributed solar projects in the Midwest. A copy of my resume is attached as Exhibit ELPC-VS 1.01 (WK-1).

I received a Master of Public & Private Management degree from the Yale University School of Management with a concentration in Regulation and Competitive Strategy. My research in graduate school focused on regulatory theory and practice. I also have a Bachelor of Science in Foreign Service from Georgetown University.

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

A: Yes. I provided testimony in the following proceedings before the ICC:

- ComEd Rider POGCS Revision: Direct and Rebuttal (19-1121)
- Ameren DG Rebate: Direct (20-0389)
- Ameren Rider NM Compliance: Direct and Rebuttal (20-0738)

Q: Have you testified or provided comments in similar state regulatory proceedings?

A: Yes. I have provided testimony in rate cases before the Michigan Public Service Commission, the Iowa Utilities Board, and the Wisconsin Public Service Commission. I have provided testimony on community solar services, the value of distributed energy resources, and the calculation of distributed generation penetration before the Michigan Public Service Commission and the Indiana Utility Regulatory Commission. I have provided comments in numerous other proceedings before the Michigan Public Service Commission, the Illinois Commerce Commission, the Illinois Power Agency, the Minnesota Public Utility Commission, and the Wisconsin Public Service Commission. A list of testimony and comments that I have filed is included as ELPC-VS 1.02 (WK-2).

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- ELPC-VS Exhibit 1.01 (WDK-1): Resume of William D. Kenworthy
- ELPC-VS Exhibit 1.02 (WDK-2): Testimony and Comments of William D. Kenworthy
- ELPC-VS Exhibit 1.03: ComEd's response to JNGO 1.01 in Docket No. 20-0700

II. BACKGROUND AND SUMMARY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to address aspects of the Commonwealth Edison Company's ("ComEd") proposed *Performance Metrics Plan* filed in the in ICC Docket No. 22-0067 on January 20, 2022.[1] Specifically, I will address concerns with several of the metrics proposed by ComEd and recommend alternatives to the reliability and interconnection metrics proposed by ComEd.

Q: Why has ComEd proposed the Plan?

A: Public Act 102-0662 (colloquially known as the Clean Energy Jobs Act ("CEJA")) became law September 15, 2021. The new Section 16-108.18 on performance-based ratemaking[2] ("PBR") permits an electric utility that serves more than 500,000 retail customers in the State and that had a performance-based formula rate in effect under the Energy Infrastructure Modernization Act (EIMA)[3] as of December 31, 2020, to, by January 20, 2023, and at the utility's election, file either a general rate case under Section 9-201 of the

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[1] Commonwealth Edison Company, *Performance Metrics Plan*, ComEd Ex 1.01 filed in *Petition for the Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act*, ICC Case No. 22-0067, January 20, 2022.

[2] 220 ILCS 5/16-108.18

[3] Energy Infrastructure Modernization Act (EIMA) Public Act 97-0616, 220 ILCS 5/16-108.5.

Act,[4] or a petition for approval of an initial multi-year rate plan under the new Performance-based ratemaking Section 16-108.18.

Utilities that elect the multi-year rate plans are required to file petitions for approval of proposed performance incentive mechanisms ("PIMs") by January 20, 2022.[5] Section 16-108.18(e)(1) describes the objectives of the PIMs in the performance plans:

> It is therefore in the State's interest for the Commission to establish performance incentive mechanisms in order to better tie utility revenues to performance and customer benefits, accelerate progress on Illinois energy and other goals, ensure equity and affordability of rates for all customers, including low-income customers, and hold utilities publicly accountable.[6]

Q: What are the required elements of the performance metrics plans?

A: Section 16-108.18(e)(2)(A) of the Act provides that the Commission may approve up to eight metrics, and it must approve at least one metric from each of six enumerated performance metrics categories:

- reliability and resiliency;
- peak load reduction;
- supplier diversity;
- affordable customer delivery service costs;
- interconnection; and
- customer service.[7]

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[4] 220 ILCS 5/9-201.
[5] 220 ILCS 5/16-108.18(e)(6)(A)
[6] Section 16-108(e)(1) sets out objectives of PIMs.
[7] 220 ILCS 5/16-108.18(e)(2)(A).

The statute also provides additional detail on each of the required performance metrics.[8] The Commission has the authority to approve up to eight metrics, meaning in addition to the six required metrics, two additional metrics could be adopted.

III. RELIABILITY METRIC: LOCATIONAL RELIABILITY

A. Statutory Requirement

Q: Please describe the statutorily required metric related to overall and locational reliability and resiliency.

A: The required overall and locational reliability and resiliency metric is Section 16-108(e)(2)(A)(i)

> (i) Metrics designed to ensure the utility maintains and improves the high standards of both overall and locational reliability and resiliency, and makes improvements in power quality, including and particularly in environmental justice and equity investment eligible communities.

Also, it should be noted that the PBR framework requires the Commission to approve plans that ensure "no degradation in the significant performance improvement achieved through previously established performance metrics."[9] Thus, the performance achieved as a result of EIMA must be maintained. The reliability performance as of the end of the EIMA (the last year will be 2023) is effectively a floor for reliability performance going forward. CEJA however establishes a new standard related to equity that must be incorporated into future reliability metrics, as discussed below.

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[8] 220 ILCS 5/16-108.18(e)(2)(A)(i) – (v).
[9] Section 16-108.18(e)(2).

B. Background on ComEd's Reliability Performance

Q: What reliability performance metrics were required of ComEd under EIMA?

A: An important part of the background for the reliability metric for this proceeding is the performance metrics related to EIMA.[10] EIMA required improvements over a ten-year period (2013 to 2023) for ten metrics in reliability, service quality targets, billing quality, consumption on inactive meters, unaccounted for energy, uncollectible expenses and opportunities for minority and women-owned businesses.

Q: Please explain the reliability metrics that are currently in use in Illinois under EIMA and that ComEd proposes here.

A: The Institute of Electrical and Electronics Engineers (IEEE) publishes the industry standard for measuring electric reliability.[11] The standard defines a number of reliability metrics and provides guidance on data collection and calculation of the various metrics. Two of these metrics are already in use in Illinois pursuant to EIMA:[12]

- System Average Interruption Frequency Index (SAIFI) quantifies the sustained duration of outages, measuring the total duration of interruption for the average customer during defined time, usually per year. It is the ratio of the total number of customers interrupted by any outage to the total number of customers in the system.

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[10] 220 ILCS 5/16-108.5(f).
[11] Institute of Electrical and Electronics Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, May 31, 2012.
[12] 220 ILCS 5/16-108.5(f).

- Customer Average Interruption Duration Index (CAIDI) measures the total minutes of customer interruption divided by the total number of customers interrupted.

In addition, EIMA established performance incentives for utilities to reduce the number of "customers who exceed the service reliability targets as set forth in subparagraphs (A) through (C) of paragraph (4) of subsection (b) of 83 Ill. Admin. Code Part 411.140 as of May 1, 2011."[13]

In this docket ComEd has proposed to use another IEEE metric to measure overall system performance -- the System Average Interruption Duration Index (SAIDI), SAIDI represents the total duration of interruption for the average customer during the reporting period, in this case one year. It is calculated by multiplying the average duration of customer interruptions by the total number of interruptions and then dividing by the total number of customers in the system.

Q: What has ComEd proposed to meet the system and locational reliability and resilience performance metric requirement?

A: ComEd proposes three reliability/resilience performance metrics to meet the requirements of Section 16-108.18(e)(2)(i). The three metrics are intended to address "the three topics identified in the statute – namely (i) improvement in overall system reliability and resiliency, (ii) improvements in power quality, and (iii) improvements in locational

[13] 220 ILCS 5/16-108.5 (f)(4).

reliability, resiliency, and power quality, including in environmental justice and equity investment eligible communities."[14] ComEd's proposed metrics for this category are:

1. SAIDI,
2. the number of customers exceeding minimum service levels of reliability or resiliency, and
3. a "System Visibility Index" (described below).

The first proposed metric, SAIDI, is the most straightforward. The proposed metric would measure SAIDI and benchmark performance against a 2021-2023 baseline to be provided in a compliance filing in the first quarter of 2024. "The incremental annual targets will be established such that, in order to earn an incentive in the first year, ComEd must achieve an incremental improvement of 1.5% over the baseline. In subsequent years, ComEd must achieve incremental improvements of 1.5% from the minimum incremental annual target eligible for incentives in the prior year."[15]

The second proposed metric in this category would be the based on the number of customers experiencing service quality disruptions, defined as:

- Customers experiencing four or more interruptions per year for three consecutive years; and
- Customers experiencing at least one 12-hour interruption per year for three consecutive years.

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[14] Direct Testimony of William Fluhler, Commonwealth Edison, *Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act*, Docket No. 22-0067, ComEd Exhibit 2.0. Pg. 4
[15] Fluhler Direct, pg. 5.

The third proposed metric in this category is the System Visibility Index, which measures "the percent of distribution system sections (station bus, circuit mainstem, and lateral segments) visible, the communication health of those sections, and the integrity and utility of that telemetry and control."[16] Mr. Fluhler explains that the System Visibility Index "evaluates visibility of system elements, and the health of the communication and control devices that can be used to diagnose and improve power quality."[17]

In addition to the proposed reliability performance metrics, ComEd proposes three tracking metrics in the "Equity" category, including one tracking metric titled "IEEE and All-In Regional SAIDI," which measures regional SAIDI as defined by IEEE. The tracking metric is further explained by Mr. Fluhler, who explains that the metric proposes to track SAIDI including major event days ("MEDs") at the regional level compared to SAIDI at the regional level without MEDs.[18]

Q: Does ComEd's proposed "Overall Reliability and Resiliency Based on SAIDI" metric meet the statutory requirement to improve reliability and resiliency "including and particularly in environmental justice and equity investment eligible communities?"

A: The SAIDI performance metric does not address the requirement to ensure that reliability and resilience outcomes are equitable for environmental justice and equity investment eligible communities. SAIDI is defined as a system-wide metric. It can be measured at more granular levels, such as the region, but is intended to measure performance at a system

[16] Fluhler Direct, pg. 11.
[17] Fluhler Direct, pg. 11.
[18] According to ComEd's Reliability Report, ComEds's transmission and distribution system is divided into four operating areas: Chicago, Northwest, Northeast and Southern. Accessed April 4, 2022: https://icc.illinois.gov/industry-reports/electric-reliability

level. However, EJ/EIE communities are defined at a much more granular level in the statute (the census tract and census block group level, as will be discussed in greater detail below). As such, a meaningful measure of reliability and resiliency in EJ/EIE communities must use metrics at a comparable level of granularity.

Q: Does the proposed metric for "Customers Exceeding Minimum Service Levels of Reliability or Resiliency" advance reliability and service quality goals "including and particularly in environmental justice and equity investment eligible communities"?

A: The two concepts addressed in ComEd's second reliability metric are customers experiencing multiple interruptions (CEMI) and customers experiencing long-duration interruptions (CELI). However, ComEd proposes to include only customers whose service quality falls below the standards proposed for three consecutive years. These two measures are valuable indicators of service quality outcomes at the customer level. However, as proposed, just as with the first metric, they measure a system-wide dimension of performance and do not relate performance in EJ/EIE communities to system-wide performance.

Q: What value to customers does the Company suggest arise from improved grid visibility, as measured by ComEd's proposed System Visibility Index?

A: Mr. Fluhler argues that improved visibility provides ComEd with an improved ability to monitor and manage momentary events.

> Improved system visibility benefits customers because it provides ComEd with visibility, and the ability to respond to, momentary events

> and voltage fluctuations that may be experienced by customers as power quality events.[19]

Q: Do you agree that ComEd's ability to respond to momentary events are an important dimension of system reliability and customer performance?

A: Momentary interruptions and variations in power quality, including voltage fluctuations, are an important dimension of service quality. However, ComEd's proposed visibility metric is tied to whether or not certain hardware exists on ComEd's grid, not whether the system is actually reducing interruptions and variations in power quality. In other words, it is not really a *performance* metric, it is an investment metric. ComEd already has a financial incentive to make capital investments in new hardware on the distribution system through its regulated rate of return. To the extent that these system visibility investments are cost–beneficial, then ComEd should propose them in the Integrated Grid Plans and seek cost recovery under the Multi-Year Rate Plans or a traditional rate case. They should not require an additional performance incentive.

Q: Is there a more appropriate way to structure a performance metric to directly address momentary interruptions and variations in power quality?

A: Yes. In my opinion, a meaningful performance incentive mechanism could be framed in terms of observable system performance outcomes using industry standards such as:

- MAIFI: Momentary Average Interruption Frequency Index;
- MAIFIE: Momentary Average Interruption Event Frequency Index; and

[19] Fluhler Direct, pg. 14.

- CEMSMI: Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events.

These important measures could be incorporated in future performance incentive mechanisms pursuant to Section 16-108.18(e)(4), and I recommend that they be included in the current Plan as tracking metrics.

Q: Does the proposed metric for the proposed "System Visibility Index" advance reliability and service quality goals in EJ/EIE communities?

A: As with the first two metrics that ComEd proposes in the reliability and resiliency category, the System Visibility Index is not directly tied to measuring the reliability and resilience outcomes experienced by EJ/EIE communities. In addition, while having greater visibility into the moment-by-moment state of all parts of the distribution system will improve the Company's ability to identify, respond to, and prevent service interruptions or service quality deviations, the cost beneficial deployment of capital to achieve such goals should be undertaken in the normal course of business and should not require an additional performance incentive mechanism.

C. Recommendations

Q: Please explain why it is important to ensure that reliability outcomes are equitable for all customers, especially those in disadvantaged communities, as required by statute.

A: The issue of measuring and incentivizing equitable customer reliability and service quality in disadvantaged communities has been receiving increasing attention in other states in the last several years. Having participated in grid modernization and distribution system planning proceedings in several states in the Midwest, I have been working with partners to bring to light the emerging understanding of grid equity in distribution system planning and investment.[20] These concepts of environmental justice and equity are embedded throughout the Public Utilities Act as amended by CEJA.

Q: Please elaborate on the concept of grid equity that you propose to incorporate into the performance metric for locational reliability.

A: There has not been a systematic approach to understanding to what extent or whether disadvantaged communities in Illinois have been disproportionately impacted by poor reliability, underinvestment in distribution systems, and/or other dimensions of distribution system performance such as hosting capacity or power quality. To my knowledge, no state in the region (indeed in the nation) has explicitly incorporated equity into the distribution system planning, investment, and spending decisions of utilities.

CEJA took a giant step forward in introducing equity as an explicit goal of all utility planning processes. Equity is clearly established as a goal in CEJA. The question that arises in the context of this performance metric is how to apply the requirement in statute to achieving the goal of equitable reliability and resilience in disadvantaged communities.

This performance metrics docket is the first of several upcoming dockets in which the issue of "grid equity" will be salient, and as such, I propose a definition here that can then be extended to other pertinent dockets in which equity in distribution system planning and investment will be considered.

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[20] Comments and Testimony in ELPC/VS Exhibit 1.02.

As Professors Gabe Chan and Alexandra Klass [21] in a forthcoming law review article, "rate setting is and always has been social policy implemented within a legislative framework designed to promote the public interest."[22] They conclude that "energy justice" is therefore just one component of "just and reasonable" rates.

> Since the early development of U.S. energy system governance, federal and state legislation has granted energy system regulators significant leeway in regulating private energy companies to advance the "public interest," in part by ensuring just, reasonable, and nondiscriminatory rates, charges, and practices. [23]

These foundational legal principles and norms provide regulators with the authority and, arguably, the duty to ensure that all members of the public enjoy equitable access to utility products and services on just and reasonable terms. CEJA makes this duty explicit.

In this frame, the Commission should not consider ComEd's performance metrics plan in a vacuum. The performance metrics are an important part of the overall statutory framework to advance clean and equitable energy outcomes. As such, the Commission should ensure that equity is infused throughout each element of the new regulatory paradigm, not just the narrow goals defined in any particular section.

CEJA is ambitious and audacious in its goals. The performance goals and metrics that I will propose in the coming responses will advance achieving the broader equity and clean energy goals that pervade the statute.

Q: What do you propose as a locational reliability and equity metric?

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[22] Gabriel Chan and Alexandra Klass, Regulating for Energy Justice, New York University Law Review (forthcoming 2022), at p. 7 (available at https://ssrn.com/abstract=4032969) (advance copy used with authors' permission).

[23] *Regulating for Energy Justice*, pg 3.

A: I endorse the Reliability and Resiliency in Vulnerable Communities (RRVC) metric proposed by Witness Andrew Barbeau. Mr. Barbeau's RRVC metric improves on recent work done in this area in Michigan and Minnesota (discussed in detail below).

The proposed metric (detailed in Mr. Barbeau's testimony) is calculated by comparing several reliability indices for customers located in Equity Investment Eligible Communities to the indices for customers not located in Equity Investment Eligible Communities in a similar geography.

Mr. Barbeau proposes a three-step calculation that:

- Calculates the reliability and resiliency indices for Equity Eligible Communities and non-Equity Eligible Communities in each county;
- Calculates the reliability and resiliency comparison for each County; and
- Calculates the weighted system-wide totals.

The final metric proposed by Mr. Barbeau is meaningful in understanding the reliability relationship between disadvantaged communities and the rest of the customer population.

Q: What is the appropriate geographic and demographic level of analysis for this performance metric?

A: One important consideration in this analysis is the granularity of the demographic and customer data used to conduct the analysis. Having participated in stakeholder groups in Minnesota and Michigan on this topic over the past two years, I recommend that the appropriate level of analysis is aggregated customer premise data at the census block group level.

Q: Please explain why you propose the census block group as the appropriate level of analysis.

A: The US Census Bureau has three levels of analysis that could be considered for this metric:

- Census Block: smallest geographic unit used by the U.S. Census Bureau for tabulation of 100- percent data (data collected from all houses, rather than a sample of houses). Demographic information by Census Block is updated every 10 years.
- Census Block Group: The census block groups consist of a cluster of census blocks. There are on average about 39 blocks per block group and generally contain between 600 and 3,000 people with an optimum size of 1,500 people. A Block Group is the smallest geographical unit for which the Census Bureau publishes sample data (5-year estimate), which is updated each year in December.
- Census Tracts: small, relatively permanent statistical subdivisions of a county delineated by local participants as part of the U.S. Census Bureau's Participant Statistical Areas Program. Census tracts were first used in the 2000 Census. Census tracts generally have between 1,500 and 8,000 people, with an optimum size of 4,000 people. Census tracts are designed to be homogeneous with respect to population characteristics, economic status, and living conditions.

Q: Based on your experience and the data available, what is the appropriate level of analysis for this metric?

A: The census block group would be the most appropriate level of analysis for this metric for three reasons. First, according to the Census Bureau, Illinois has 3,123 census tracts, 9,691 block groups, and 451,554 census blocks.[24] Using the census block level would result in an unwieldy data set that significantly increases the complexity of the analysis.

Second, there are two data sets that are used to define EJ/EIE communities in the Public Utilities Act:

> "Equity investment eligible community" means the geographic areas throughout Illinois which would most benefit from equitable investments by the State designed to combat discrimination. Specifically, the equity investment eligible communities shall be defined as the following areas:
>
> (1) R3 Areas as established pursuant to Section 10-40 of the Cannabis Regulation and Tax Act, where residents have historically been excluded from economic opportunities, including opportunities in the energy sector; and
>
> (2) Environmental justice communities, as defined by the Illinois Power Agency pursuant to the Illinois Power Agency Act, where residents have historically been subject to disproportionate burdens of pollution, including pollution from the energy sector.[25]

Of these two data sets, the R3 areas are defined at the census tract level and the EJ communities are defined at the census block group level. Given that the census block group is the most granular level of analysis for the two data sets, that is the most granular level of analysis available.

Third, the next most granular level of analysis, the census block level data is only updated every ten years in conjunction with the Decennial census, which surveys every household. The census block group demographic data is updated annually through the

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[24] https://www.census.gov/geographies/reference-files/2010/geo/state-local-geo-guides-2010/illinois.html
[25] 220 ILCS 5/16-108.18(b).

American Community Survey and is available each December. The US Census Bureau's American Community Survey publishes detailed demographic, social, and economic statistics based on continuous survey (sampling) data collection. For the census block group level, the data is collected over the most recent five years and batched, summarized, and published the following December. Using data from five years provides increased statistical reliability and smaller margins of error.

Q: Please elaborate on your experience in other regulatory proceedings relating to the measurement of locational reliability and equity.

A: Since 2019, I have participated in and commented on the topic of locational reliability and equity in a series of dockets in Minnesota, including:

- Performance Based Ratemaking: *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations* (PUC Docket No: E002/CI-17-401)
- Distribution System Planning:
  - *In the Matter of Xcel Energy's 2019 Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security Certification Request* (PUC Docket No: E002/M-19-666)
  - *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project,* (PUC Docket No: E002/M-21-694)
- Safety Reliability and Service Quality:

- *In the Matter of Minnesota Power, Otter Tail Power, and Xcel Energy's Compliance with Annual Safety, Reliability, and Service Quality Metrics for 2020* (Docket No. E002/M-21-237)
- *In the Matter of Minnesota Power, Otter Tail Power, and Xcel Energy's Compliance with Annual Safety, Reliability, and Service Quality Metrics for 2019* (Docket No. E002/M-20-406).

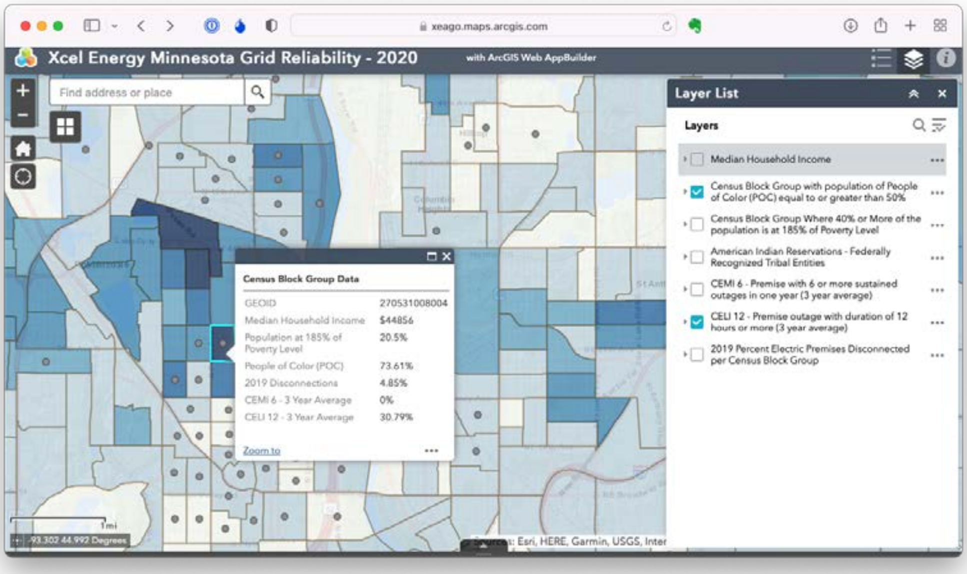
Across all these dockets, in combination with several different partners, including the Environmental Law & Policy Center, I have participated, contributed, and advocated for the Commission to require Xcel to develop a metric and performance incentive related to equity and reliability in disadvantaged communities.

A watershed moment in this progression occurred in a December 18, 2020 Order in Docket No. 20-406, in which the Minnesota Public Utilities Commission (MPUC) directed Xcel to develop and publish an interactive map with locational reliability data. Xcel provided an update along with an illustrative sample map on October 1, 2021 and released a system-wide Grid Reliability Map on December 15, 2021.[26] The map overlays demographic data with disconnection data and two customer-oriented reliability metrics:

- customers experiencing long interruptions of 12 hours or more (CELI-12) and
- customers experiencing multiple interruptions six or more times per year (CEMI-6)

[26] Xcel provided links to the October 1, 2021 and December 15, 2021 maps in letters filed with the Commission in the 2020 and 2021 SRSQ dockets and the performance metrics docket (Docket No. E002/M-20-406, E002/M-21-237, and E002/CI-17-401).

These three measures with customer data aggregated at the census block group level are then layered onto a map with three additional layers for demographic data: poverty rate, percent of people of color (POC), and median income at the census block group level.



The map is available here:

[Xcel Energy Minnesota Grid Reliability Map - (arcgis.com)]

Xcel Energy, to its credit, has participated actively in this process and, to my knowledge, led the nation by producing this map. The MPUC continues to be interested in this issue and has indicated that it supports the eventual adoption of a locational reliability metric.

Similarly, there has been considerable effort toward measuring locational reliability and equity in Michigan. While it has been discussed in workshops informally for several years, DTE Energy in its most recently filed Integrated Distribution Plan indicated its intention to correlate reliability performance with census tract level data:

> To assess our current state, DTEE intends to use the forthcoming MIEJScreen, which will provide a consistent data set and approach across the state for defining highly impacted communities within our service territory. The screening tool will generate a scale for rating each census-tract level community based on a comprehensive list of indicators that include environmental exposures and effects, sensitive populations, and socioeconomic factors.[27]

Vote Solar, ELPC, and our partners in Michigan (the Natural Resources Defense Council, the Michigan Environmental Council, Union of Concerned Scientists and The Ecology Center) provided comments on the Company's proposed approach on October 1, 2021.[28]

In summary, while there has been significant and meaningful progress across the Midwest on the measurement of locational reliability and equity, CEJA launched Illinois into a leadership role in the region -- and to my knowledge, across the nation -- on the topic of measuring and incentivizing distribution system reliability performance in disadvantaged communities. Therefore, the Commission should ensure that Illinois utilities do not lag behind utilities in neighboring states on developing tools to assess locational reliability and equity. I endorse the Reliability and Resiliency in Vulnerable Communities (RRVC) metric proposed by Witness Andrew Barbeau as an important first step that improves on the recent work done in this area in Michigan and Minnesota.

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[27] DTE Electric Company, *2021 Distribution Grid Plan Final Report*, September 30, 2021 MPSC Case No. U-20147, pg. 26.
[28] Joint Comments of the Environmental Groups in Response to the Commission's August 25, 2021 Invitation for Stakeholder Feedback, *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters*, Michigan Public Service Commission Docket No. 20147, October 1, 2021.

IV. INTERCONNECTION AND DER INTEGRATION METRIC

A. Statutory Requirement and ComEd Proposal

Q: What are distributed energy resources (DER)?

A. While distributed energy resources ("DER") are often defined broadly to include distributed generation (wind and solar) and storage, along with energy efficiency, demand response and other load management resources, in the context of this metric, DER include resources interconnected to the grid pursuant to the interconnection rules in 83 Ill Admin Code 466, Electric Interconnection of Distributed Generation Facilities (Part 466) and 83 Ill Admin Code 467, Electric Interconnection of Large Distributed Generation Facilities (Part 467).

Q: What is the statutory requirement for a metric related to DER interconnection and integration in Section 16-108.18(e)(2)(A)(v)?

A: Section 16-108.18(e)(2)(A)(v) contains broad language that requires a performance metric that addresses DER interconnection and integration across a menu of possible DER and rate-related categories:

> (v) Metrics designed around the utility's timeliness to customer requests for interconnection in key milestone areas, such as: initial response, supplemental review, and system feasibility study; improved average service reliability index for those customers that have interconnected a distributed renewable energy generation device to the utility's distribution system and are lawfully taking service under an applicable tariff; offering a variety of affordable rate options, including demand response, time of use rates for delivery and supply, real-time pricing rates for supply; comprehensive and predictable net metering, and maximizing the benefits of grid modernization and clean energy for ratepayers; and

> improving customer access to utility system information according to consumer demand and interest.[29]

Q: What DER metric has ComEd proposed?

A: ComEd has proposed an indexed metric based on the mean number of business days saved for utility-performed interconnection tasks set forth in the Part 466 interconnection rules, weighted by volume of interconnection requests received in each level.[30] The Company collected these tasks in Table 5[31] of Mr. Fluhler's direct testimony and reproduced below as Figure 1:

Application Level	Task Name	Days Allotted
Level 1	All tasks aggregated	22
Level 2, 3 & 4	Completeness Review	10
Level 2 & 3	Expedited Review	20
Level 2	Supplemental Review	30
Level 4	Feasibility Study	25
Level 4	System Impact Study	25
Level 4	Combined Study[5]	50
Level 4	Facilities Study	30

Figure 1: Utility Performed Interconnection Application Processing Tasks in Part 466

Q: Why does the Company propose reducing the interconnection application processing timelines?

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[29] 220 ILCS 5/16-108.18(e)(2)(A)(v).
[30] Fluhler Direct, pg. 15.
[31] Fluhler Direct, pg. 16.

A: The Company asserts that improving application processing times for interconnection customers primarily benefits the interconnection applicants and that such benefits vary widely. Mr. Fluhler concludes:

> The benefits arising from achievement of this metric primarily accrue to the individual customers interconnected to ComEd's system, and therefore vary widely according to the varying economics and other drivers of the customers' requests for interconnection. Thus, although it is clear that reduced interconnection processing time benefits customers, it is not practical to quantify the benefits.[32]

Q: Do you agree that accelerating the processing of applications is a desirable outcome?

A: Yes. The ability of customers to interconnect distributed energy resources to the grid is a fundamental feature of the modern grid envisioned in CEJA (as discussed above). In order to fulfill that vision, timely and fair processing of interconnection applications is needed to keep costs low for interconnecting customers while ensuring safety and reliability for the grid. In addition, transparency can provide regulators and other stakeholders with assurance that applications are being processed in accordance with statutory and administrative requirements.

Q: What is ComEd's current performance regarding the processing of interconnection applications?

A: It's not clear. There is currently no transparency as to ComEd's compliance with required processing times or with the accuracy of ComEd's cost estimates for distribution facilities upgrades, especially for advanced studies of larger projects.

[32] Fluhler Direct, pg. 18.

Parties in Illinois, including ComEd, Vote Solar/ELPC, and many others have invested significant resources since February 2020 in stakeholder workshops and the subsequent interconnection rulemaking to update the interconnection rules in 83 Ill Admin Code 466, Electric Interconnection of Distributed Generation Facilities (Part 466) and 83 Ill Admin Code 467, Electric Interconnection of Large Distributed Generation Facilities (Part 467). During the formal interconnection rulemaking process in ICC Docket 20-0700, the Joint Non-governmental Organizations (ELPC, NRDC, Interstate Renewable Energy Council, and Vote Solar) submitted data requests regarding the timing and cost of ComEd's interconnection process. ComEd did not respond to these data requests, claiming that the interconnection application processing timeline and cost estimate data was not relevant to the interconnection rules proceeding, among other grounds. After stating general objections, ComEd maintained, "The results of analysis of individual interconnection applications are not relevant to the revisions of the interconnection rules." (ComEd response in JOINT NGO-COMED 1.01 in Docket No. 20-0700, attached as Exhibit 1.03). Unlike Ameren, ComEd does make some information about its interconnection application process available through the interconnection queue report available on its website, however the published interconnection queue does not contain timeline or cost data that would be needed to verify performance.[33]

Q: Should the Commission begin gathering evidence and tracking whether interconnection processing times become a barrier as customers install more distributed generation?

[33] https://www.comed.com/SmartEnergy/MyGreenPowerConnection/Pages/InterconnectionQueue.aspx

A: Yes. As discussed further below, I recommend that the Commission adopt several additional tracking metrics which should be published in a public interconnection queue designed to provide transparency in the interconnection process. The proposed tracking metrics are designed to ensure that ComEd is meeting or exceeding the requirements of the updated Part 466 and 467 interconnection rules (currently pending before the Joint Committee on Administrative Rules). The metrics proposed by ComEd should be included as part of these new tracking metrics, but I recommend that the reporting be expanded to provide data on broader interconnection application processing deadlines and cost transparency, as described below.

Q: Is the Company's proposed interconnection metric an appropriate metric for a performance incentive?

A: No. ComEd has not demonstrated that a performance incentive to marginally improve on the Part 466 deadlines would advance broader public policy goals enshrined in CEJA. In my opinion, performance metrics should be reserved to encourage behavior that is difficult to address through traditional cost of service ratemaking. Moreover, ComEd's proposed interconnection metric focuses only on the timing of the interconnection process, but it does not incentivize the goals of broad DER adoption and value creation manifest throughout CEJA. Neither does it substantially improve customer service or accelerate progress on the state's clean energy goals. I propose a more meaningful metric below that is designed to reward ComEd's performance in creating grid value by interconnecting and utilizing customer-owned DER.

Q: What is your understanding of CEJA's goals for the DER metric?

A: The language of the DER interconnection metric in sub-paragraph (v) of Section 16-108.18(e)(2) of the Public Utilities Act is very broad and includes a number of critical concepts pertinent to the statutory goal of expansion and integration of distributed generation, including: rate design, net metering, grid modernization, and data access.[34] In order to put this metric in context, it is important to look to CEJA's broader DER goals. CEJA contains multiple overlapping programs that focus on increased deployment of customer-owned DER to provide value to the utility system and all ratepayers. One of the overarching objectives of the new performance-based ratemaking process is to:

> (3) direct electric utilities to make cost-effective investments that support achievement of Illinois' clean energy policies, including, at a minimum, investments designed to integrate distributed energy resources, comply with critical infrastructure protection standards, plans, and industry best practices, and support and take advantage of potential benefits from the electric vehicle charging and other electrification, while mitigating the impacts;[35]

The statute also contains a new Multi-Year Integrated Grid Planning process (Section 16-105.17) and a significantly amended DG Rebate section (Section 16-107.6) that require utilities to plan and compensate DERs for the value they create on the grid. For example, the utilities' Multi-Year Grid Plans must include:

> Identification of potential cost-effective solutions from nontraditional and third party owned investments that could meet anticipated grid needs, including, but not limited to, distributed energy resources procurements, tariffs or contracts, programmatic solutions, rate design options, technologies or programs that facilitate load flexibility, nonwires alternatives, and other solutions that are intended to meet the objectives described at subsection (d).[36]

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[34] 220 ILCS 5/16-108.18(e)(2)(A)(v).
[35] 220 ILCS 5/16-108.18(c)(3).
[36] 220 ILCS 5/16-105.17(f)(2)(K).

The Grid Plans must be designed to "achieve the metrics" approved by the Commission in this docket.[37] Therefore, the Commission should strive to set metrics in this docket that relate to the broader DER-related objectives and outcomes in the Grid Planning section and throughout CEJA.

Q: Why shouldn't the Commission award ComEd a performance incentive for marginally improving on its interconnection timelines?

A: One of the important principles enshrined in statute related to this proceeding is that performance metrics must be designed to achieve additional, difficult to achieve improvements over baseline performance values and targets. For example, the Staff report on the performance metrics workshops noted that a number of commenters proposed a principle that performance metrics should incentivize behavior that is difficult to address through traditional cost of service ratemaking.

> Some stakeholders recommend ensuring that performance measures provide incentives that do not otherwise exist. Vote Solar recommended that performance metrics be designed to incent achievement of goals that are not incented elsewhere, for example, that are not incented through traditional ratemaking processes. It recommended that particular attention be paid to ensure that performance metrics do not duplicate or undermine desirable incentives already addressed through the ratemaking framework. EDF similarly recommended metrics that provide incentives where the traditional regulatory compact would otherwise not incentivize utility actions.[38]

When considering utility performance incentive plans, the Commission should only approve PIMs designed to achieve outcomes that are difficult to address through traditional

[37] 220 ILCS 5/16-105.17(f)(1)(B).
[38] Staff of the ICC and Rocky Mountain Institute, *Performance and Tracking Metrics Workshop Summary pursuant to 220 ILCS 5/16-108.18(e)*, December 1, 2021, pg. 7.

ratemaking tools and based on specific statutory objectives. The PIMs should not compensate utilities for achieving baseline performance required under statute.[39]

Timely processing of interconnection applications is required by statute and (current and future) administrative rules. There is no evidence to suggest that incremental acceleration customer interconnection applications will advance the DER integration goals that are manifest throughout the statute. ComEd's interconnection metric therefore proposes a performance incentive to solve a problem that it has not shown exists.

As an alternative, I suggest that the Company and the Commission focus on a more meaningful interconnection metric that rewards ComEd for creating grid value directly related to DER interconnection and integration. Specifically, I recommend a DER interconnection and integration metric to incentivize the Company to utilize DER to achieve broader energy policy goals espoused in CEJA, including the deployment and utilization of third-party owned DERs to meet anticipated grid needs. I discuss this recommendation in more detail below.

B. Basis for a DER Integration/Interconnection Performance Metric

Q: What are the broad DER integration goals in the current PUA?

A: CEJA firmly established the importance of distributed energy resources as a critical element in achieving the clean energy transition in Illinois. Beginning with FEJA and confirmed in CEJA, the State has clearly established the importance of broadly deploying

[39] Comments of Vote Solar on Electric Utility Performance and Tracking Metrics, October 31, 2021. Accessed on March 29, 2021 at https://www.icc.illinois.gov/informal-processes/Electric-Utility-Performance-and-Tracking-Metrics.

distributed energy resources to create value on the grid. The DG Rebate program in Section 16-107.6 provides compensation to DG customers based in part on the grid services that those customers create for the energy system.[40]

The new performance-based regulatory framework created by CEJA continues the strong emphasis on DER deployment for value. In addition to 220 ILCS 5/16-108.18(c) (discussed above, establishing as one “objective” of the new performance-based ratemaking process, “investments that support achievement of Illinois' clean energy policies, including, at a minimum, investments designed to integrate distributed energy resources …”), Section 16-108.18(e)(1) clearly articulates a policy supportive of advancing DER:

> Building upon the State's goals to increase the procurement of electricity from renewable energy resources, including distributed generation and storage devices, the General Assembly finds that electric utilities should make cost-effective investments that support moving forward on Illinois' clean energy policies. It is therefore in the State's interest for the Commission to establish performance incentive mechanisms in order to better tie utility revenues to performance and customer benefits, accelerate progress on Illinois energy and other goals, ensure equity and affordability of rates for all customers, including low-income customers, and hold utilities publicly accountable.

The concept of leveraging DER for grid value is also an important goal of the distribution system plans in Section 16-105.17 which specifies that the Multi-Year Integrated Grid Plans (MYIGP) must include:

> (G) An evaluation of the short-term and long-run benefits and costs of distributed energy resources located on the distribution system, including, but not limited to, the locational, temporal, and performance-based benefits and costs of distributed energy resources. The utility shall use the results of this evaluation to inform its analysis of Solution

[40] 220 ILCS 5/16-107.6.

> Sourcing Opportunities, including nonwires alternatives, under subparagraph (K) of paragraph (2) subsection (f) of this Section. The Commission may use the data produced through this evaluation to, among other use-cases, inform the Commission's investigation and establishment of tariffs and compensation for distributed energy resources interconnecting to the utility's distribution system, including rebates provided by the electric utility pursuant to Section 16-107.6 of this Act.[41]

Thus, the MYIGPs specifically provide the framework for valuation of DER services that will be used in conjunction with the distributed generation and storage rebate programs in Section 16-107.6

Section 16-107.6 Distributed generation rebates, as amended by CEJA, includes two rebate programs that are intended to facilitate DER's providing value to the grid: one for smart inverters and another for energy storage systems.

The metric that I propose below is consistent with this broad goal of DER value creation throughout CEJA because it would incentivize the interconnection **and utilization** of DERs that provide value to the grid.

Q: Please describe the DER valuation investigation required under Section 16-107.6(e).

A: The statute directs the ICC to open an investigation by no later than June 30, 2023 "into the value of, and compensation for, distributed energy resources." The investigation must identify a "base rebate" for "system-wide grid services" but also additional compensation for "additive services."

> "(3) The Commission shall also determine, as a part of its investigation under this subsection, whether distributed energy resources can provide any additive services. Those additive services may include services that are provided through utility-controlled responses to grid conditions. If the Commission determines that distributed energy resources can

[41] 220 ILCS 5/16-105.17 (f)(2)(G).

> provide additive grid services, the Commission shall determine the terms and conditions for the operation and compensation of those services. That compensation shall be above and beyond the base rebate that the distributed energy generation, community renewable generation project and energy storage system receives. Compensation for additive services may vary by location, time, performance characteristics, technology types, or other variables.[42]

The Commission is also directed to use the grid plans to calculate the values of DER for compensation in the rebate:

> The Commission's final order concluding this proceeding shall also direct the utilities to update the formula, on an annual basis, with inputs derived from their integrated grid plans developed pursuant to Section 16-105.17.[43]

And

> The Commission shall consider the electric utility's integrated grid plan developed pursuant to Section 16-105.17 of this Act to help identify the value of distributed energy resources for the purpose of calculating the compensation described in this subsection.[44]

CEJA's innovative and novel approach to DER valuation and compensation is foundational to unlocking the potential for co-optimization of distribution, transmission, and energy supply that underlies CEJA's energy system transition policies. The identification and compensation of DER in the DG and storage rebate section of the statute closely aligns with the broad DER policy goals articulated throughout the statute. As such, the DER interconnection/integration performance metric should be linked to the achievement of DER valuation in the DG and storage rebate programs. The metric I

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[42] 220 ILCS 5/16-107.6(e).
[43] 220 ILCS 5/16-107.6(e)(2).
[44] 220 ILCS 5/16-107.6(e)(5).

propose focuses on the utilization of interconnected DER to provide value, not just the mechanical processing of interconnection applications.

Q: What is the timing of the distributed generation value investigation and subsequent tariffs established under Section 16-107.6?

A: Subsection (e) requires the Commission to initiate an "independent, statewide investigation" by no later than June 30, 2023. Following completion of the investigation (the Commission's final order), the utilities have 60 days to file updated tariffs including new tariffs for the recovery of costs incurred under subsection (e), and the Commission shall approve, or approve with modification, the tariff or tariffs within 240 days after the utility's filing. While the duration of the investigation is not specified in subsection (e), the timing of the start of the investigation was intended to make it possible for the Commission to complete the investigation, for the utilities to subsequently file tariffs, and for the Commission to take action approving or modifying them by the threshold date determined in subsection (a), which is no later than December 31, 2024.

Q: How does the timing of the subsection (e) investigation align with the timing of the implementation of these performance metrics and incentives in the initial multi-year rate plans?

A: Utilities that elect to file multi-year **rate plans** pursuant to Section 16-108.18 must file them no later than January 20, 2023 for delivery service rates to be effective for 2024-2027.[45] In addition, as previously noted, this performance metrics docket requires the

[45] "If an electric utility had a performance-based formula rate in effect under Section 16-108.5 as of December 31, 2020, then the utility may file a petition proposing tariffs implementing a 4-year Multi-Year Rate Plan as provided

performance metrics to be set in this proceeding and incorporated in the **integrated grid plans** that will be filed by the utilities by January 20, 2023.[46] Thus, the initial rate and grid plans are filed by the same date, which is prior to the completion of the DG rebate Section 16-107.6(e) investigation.

Q: Does Illinois have the processes and regulatory tools in place to accurately identify and value DER as directed by Section 16-107.6?

A: Yes. CEJA's creation of a new distribution planning process in Illinois allows the Commission to more accurately identify the value that DERs can provide to the grid. CEJA established a robust combination of regulatory processes and tools that should facilitate the DER value investigation under Section 16-107.6(e), the Multi-Year Integrated Grid Plans, the Multi-Year Rate Plans, and this performance metrics and incentives process. All of these programs are interrelated and should be considered together when establishing performance incentives metrics in this docket.

C. Recommendation

Q: Please summarize your proposed DER Integration and Interconnection metric.

A: I propose that the Commission replace ComEd's narrow interconnection metric with a broader DER Integration & Interconnection Metric (DII Metric) that is based on the incremental benefits of DER that are realized through the integration and utilization of DER as expressed and measured in the Multi-Year Integrated Grid Plan and DG Rebate proceedings. Section 16-107.6 establishes the DG and storage rebates and provides for the

in this Section no later than, January 20, 2023, for delivery service rates to be effective for the billing periods January 1, 2024 through December 31, 2027." 220 ILCS 5/16-108.18(d)(1)

[46] 220 ILCS 5/16-105.17(f)(5)(D).

utilities to earn on the regulatory asset in the programs. This provides a strong baseline for further utility actions to capture additional values of DER and to ensure that the benefits accrue to the grid as a whole and achieve statutory goals for DER expansion.

The metric I propose would be linked to a percentage (10%) of the incremental savings or value created from the tariffs and/or programs that ComEd will implement pursuant to the upcoming Section 16-107.6(e) investigation of DER value that exceed the base rebate values for system-wide grid services under Section 16-107.6. Because those tariffs are intended to take effect in calendar year 2025, the performance metric for the first year of the performance incentive programs (2024) would be a percentage (10%) of any savings identified and captured through "additive services" that ComEd pays or credits to customers before the "threshold date" defined in the statute. These values and concepts are detailed below.

Q: What is the threshold date?

A: Section 16-107.6 establishes a threshold date for the transition to the new DG and storage rebates to be calculated based on the investigation in subsection (e). The threshold date is the later of December 31, 2024, or the effective date of new tariffs to be approved by the Commission.

Q: How would the DII PIM be calculated prior to the threshold date in Section 16-107.6?

A: Prior to the statutory threshold, I propose that the DII PIM value should be calculated as 10% of the value of "additive services" paid or credited to customers that have received the DG and/or storage rebates. An example of how "additive services" would be calculated is provided below.

Q: What are "additive services"?

A: "Additive services" are defined in Sec. 16-107.6 as services that DERs provide to the energy system and society that are not already captured in the "base rebates" offered for "system-wide" grid services. "System-wide" grid services are the benefits that a distributed energy resource provides to the distribution grid simply by existing on the grid. System-wide grid services "do not vary by location, time, or the performance characteristics of the distributed energy resource." "Additive services" may reflect, but are not limited to, the locational and time-based benefits of DERs that vary depending on where, when, and how the DERs are deployed. Therefore, "additive services" will typically require some kind of utility program to capture this value, including "services that are provided through utility-controlled responses to grid conditions."[47]

Q: Can you provide some examples of the kinds of additional utility actions that could capture additional DER value and, potentially, qualify for your proposed DER Integration & Interconnection Metric?

A: A few examples of the types of programs and rates that the utilities could implement to leverage DER in grid beneficial ways for additive services include:

- Customer behavior modifications resulting from tariffs for DER customers designed to shape load in grid beneficial ways (i.e. highly differentiated time of use rates);
- Energy storage paired with solar systems operating to respond to grid needs, not just passively, but responding to economic signals sent by the utility or an aggregator;
- Aggregations of DER providing energy and capacity services to benefit the default supply customers supplied by the utility; or

[47] 220 ILCS 5/16-107.6(e)(3).

- Aggregations of DER to provide distribution system benefits on a system wide basis (e.g., reducing transmission service and capacity obligations to regional transmission organizations)

Q: How would the DII Metric be calculated after the Section 16-107.6(e) investigation and the threshold date?

A: After the threshold date, when the DG and storage rebate compensation rates will be based on the value of the DER identified in the subsection (e) investigation, I propose that the DII PIM be calculated based on a percentage (10%) of the value created through ComEd's actions to identify and capture DER value that is incremental to the minimum statutory rebate values for the base rebates plus the value of additive services that ComEd enables its customers to provide. This would be a two-part calculation:

- **System-wide Grid Services:** The calculation of the value created through ComEd's actions to identify and capture system-wide benefits begins with the subsection (e) investigation. In that investigation, the Commission is required to "establish an annual process and formula for the compensation of distributed generation and energy storage systems, and an initial set of inputs for that formula."[48] To the extent that the rebate value established in that investigation of system-wide benefits exceeds the statutory minimum of $250/kw, the utility would receive a percentage (proposed at 10%) of the value identified in the system-wide grid services in excess of the statutory minimum. An illustrative example is provided in the table below:

[48] 220 ILCS 5/16-107.6(e)(2).

Table 1: Illustrative Example of Base Rebate Incremental Value PIM Calculation

Line	Item	Value	Source
1	Base Rebate for System-Wide Grid Services	$ 300	From subsection (e) investigation
2	Statutory Minimum Rebate	$ 250	Set in Statute
3	Incremental Value	$ 50	Line 1 - Line 2
4	Number of Rebates Paid	1,000	
5	Total Incremental Value	$ 50,000	Line 3 * Line 4
6	Proposed PIM Rate	10%	
7	PIM Value	$ 5,000	Line 5 * Line 6

- **Additive Services:** For the calculation of the incentive metric for "additive services," the utility calculation of the value created would be the value of any "additive services" determined by the Commission in the annual determination of the value of additive services in subsections (c)(1) and (2). So for example, if the Commission determined in the annual subsection (e) calculation that reducing distribution system load between the hours of 4pm and 6pm through the use of a battery storage system was worth $10 per kilowatt per hour and the Company could demonstrate that a particular customer reduced peak load by 2 kW for one hour during those performance times through the operation of the utility's program or incentive, then the "additive services" created by that program for that hour would be $20. If the Company had 1,000 customers achieving such peak reduction, the calculated value of the "additive services" program would be worth $20,000. And the Company would receive a performance incentive for the additive services portion of this metric worth 10% of the total value, or $2,000.

Q: Please provide an example of the grid benefits that could be achieved under the soon to be available updated DG and storage rebates.

A: Section 16-107.6(c)(2) provides that before the threshold date a residential or small commercial[49] customer may receive a storage rebate provided that they "participate in a peak time rebate program, hourly pricing program, or time-of-use rate program offered by the applicable electric utility."[50] For these customers, who are enrolled in an applicable program, the utility through additional voluntary programs or incentives could identify grid beneficial actions, examples of which are provided above, for which it would be compensated via this performance metric. ComEd could also propose innovative programs to realize energy supply benefits for their default energy supply customers and to facilitate customers supplied by retail electric suppliers to utilize their DER in ways that benefit the energy supply.

Q: Do all of the implementation details for these utility programs need to be identified in this docket in order to approve your proposed DII Metric here?

A: No. The details of ComEd's programs to capture DER value will be established through the forthcoming Multi-Year Grid Planning process and DER Value Investigations, as described above. This docket sets the targets, but the specific path to reach those targets will be developed later. The proposed performance metric in this docket is defined as a percentage of savings identified and calculated elsewhere.

Q: Please summarize the proposed performance metric for DER Interconnection and Integration.

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[49] Customers eligible to receive the storage rebate are more precisely defined as "The owner or operator of distributed generation that, before the threshold date, would have been eligible for net metering under subsection (d), (d-5), or (e) of Section 16-107.5 of this Act and that has not previously received a distributed generation rebate."
[50] 220 ILCS 5/16-107.6(c)(2).

A: The table below (Table 2: DER Interconnection and Integration PIM) summarizes the proposed DER IIM.

Table 2: DER Interconnection and Integration PIM

Performance Year	Metric	Basis Points Available
Year 1 (2024)	10% of the amount credited or paid for additive services to customers participating in the DG or storage rebates	Up to 10
Year 2 (2025) or after implementation of tariffs in place implementing the values identified in Section 16-107.6.	(10% of the incremental identified benefits from system-wide grid services above minimum per kw value for base rebates times the capacity of base DG and storage rebates paid) Plus (10% of the amount credited or paid for additive services to customers participating in the DG or storage rebates)	Up to 10
Subsequent Years	Same as Year 2	Up to 10

Q: Does your recommended PIM include penalties?

A: Not at this time. Because the system benefits and savings being incentivized through this metric are not currently quantified pending completion of the subsection (e) investigation, we do not currently have a baseline or an economic potential study. As such, the proposed PIM is based only on shared savings from “additive services” (starting from zero currently calculated) as described above. In conjunction with the subsection (e) investigation, the Commission could consider an economic potential of DER study. Using such a study, the Commission could then set penalties for failing to realize certain additive services value levels. The second performance metrics workshop and performance metrics plan filing cycle in 2025/2026 required in Section 16-108.18(e)(6)(B) would be an appropriate time to consider adding penalties related to this metric.

Q: If the Commission selects a different metric to meet the requirement of Section 16-108.18(e)(2)(A)(v), would you support adoption of the DII Metric as an alternative performance metric?

A: Yes. CEJA is clear that the broad adoption of DER for value is the policy of the State of Illinois. The DER Interconnection and Integration Metric I have proposed is better aligned with the policy objectives identified in CEJA and is more consistent with the principles of performance-based ratemaking than the Level 1 interconnection incentive proposed by ComEd. The DII metric is important and merits inclusion in the performance metrics framework whether it is included as one of the six required PIMs or is included as one of the two optional PIMs.

V. TRACKING METRICS

Q: What do you recommend vis-à-vis tracking metrics for interconnection application processing?

A: Although I do not recommend that it form the basis of a performance incentive, I do believe that utility processing time for interconnection applications is an important issue that should be tracked. Also as previously mentioned, in the context of the Commission's Part 466 interconnection rulemaking proceeding, the Joint Non-Governmental Organizations both sought data on interconnection application processing through discovery and proposed rules provisions that would require additional transparency in the form of public interconnection queues and reporting on distribution facilities upgrade cost estimates and installed costs. I continue to advocate for the Commission to make this information available to provide needed transparency and visibility to interconnection customers. As such, the Commission should require tracking metrics that provide transparency and visibility into the timeliness and cost of interconnections.

Q: What, specifically, are you proposing for interconnection-related tracking metrics?

A: I recommend that the Commission require the utilities to publish public interconnection queues, updated at least monthly that include the following information in a downloadable format:

1. Project ID or Reference Number
2. Level or Type of Application (Level 1, 2, 3, or 4)
3. Type (solar, wind, etc.)
4. MVA
5. County
6. Zip Code
7. Date Application Received
8. Date Application Deemed Complete
9. Date Initial Screening Review Completed (i.e. application of the Level 1, 2, or 3 screens prior to supplemental review)
10. Supplemental Review Conducted (Y/N)
    a. Supplemental Review Completion Date (if applicable)
    b. Supplemental Review Cost Estimate (if applicable)
    c. Actual Supplemental Review Costs (if applicable)
11. Application Elevated from Level 1 to Level 4? (Y/N)

12. Application Elevated from Level 2 to Level 4? (Y/N)

13. Interconnection Feasibility Study Needed? (Y/N)

    a. Interconnection Feasibility Study Status (Complete / Incomplete)

    b. Interconnection Feasibility Study Completion Date

14. Interconnection Impact Study Needed? (Y/N)

    a. Interconnection Impact Study Status (Complete / Incomplete)

    b. Interconnection Impact Study Completion Date

15. Interconnection Facilities Study Needed? (Y/N)

    a. Interconnection Facilities Study Status (Complete / Incomplete)

    b. Interconnection Facilities Study Completion Date

    c. Interconnection Facilities Study Cost Estimate

    d. Interconnection Facilities Study Actual Cost

16. Were interconnection facilities or distribution upgrades required? (Y/N)

    a. Interconnection Facilities Construction Agreement Date

    b. Interconnection Facilities Construction Completion Date

    c. Interconnection Facilities Construction Cost Estimate

    d. Interconnection Facilities Construction Actual Cost

17. Interconnection Agreement Status (Executed / Not Executed / Withdrawn)

    a. Date Interconnection Agreement Executed

    18. Overall Project Status (Project Energized / IA Executed / Under Review / Withdrawn)

        a. Date Project Energized (if applicable)

        b. Current Stage of Review (if applicable)

c. Withdrawal Date (if applicable)

Q: Do other utilities in the region make this information available?

A: Public interconnection queues provide important visibility and transparency for DER developers and customers in our region. Specifically, I would direct the Commission's attention to the public interconnection queue published by Xcel Energy in Minnesota. While not as detailed as the information requested above, Xcel Energy reports on 17 different data dimensions. A copy of the Xcel Interconnection queue is available on their website.[51]

VI. CONCLUSION AND RECOMMENDATIONS

Q: Please summarize your findings and recommendations in this proceeding.

A: In general, ComEd has proposed metrics that will advance the goals of the Public Utilities Acts as amended by the Clean Energy Jobs Act, but ComEd's proposal falls short in some important respects. CEJA set a new standard nationally for transitioning to a clean and equitable energy future. While performance metrics have been a part of the utility landscape in Illinois since EIMA, CEJA firmly established the paramount importance of equity and recognized the benefits of distributed energy resources in the clean energy transition. The performance incentive metrics framework established in Section 16-108.18(e) provides a framework for the utilities to propose and the Commission to approve mechanisms that will advance CEJA's goals and objectives that are difficult to address or incentivize through traditional cost of service regulation.

[51] https://mn.my.xcelenergy.com/s/renewable/developers/interconnection

In light of the ambitious and forward-looking framework that CEJA establishes, the Commission should only approve performance metrics that define meaningful goals related to overarching statutory objectives that are difficult to address through traditional cost of service ratemaking. In this testimony, I have proposed performance metrics related to grid equity and DER integration/interconnection to replace the reliability and interconnection application processing metrics proposed by ComEd. While ComEd's proposed performance metric plan addresses real issues in grid modernization, the goals are not specifically and directly aligned to the most important goals of CEJA.

I urge the Commission to require ComEd to substitute the grid equity and DER interconnection/integration goals proposed herein.

Q: Does this conclude your testimony?

A: Yes