Direct Testimony

of

Daniel Ashbaugh

Electrical Engineer

Integrated Distribution Planning Division

Illinois Commerce Commission

Petition for the Establishment of Performance Metrics under Section 16-108.18(e) of the Public Utilities Act.

Commonwealth Edison Company

Docket No. 25-0514

July 28, 2025

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Attachments

Staff Exhibit 4.01 **Ameren Response to Staff Data Request (“DR”) DLA 1.03**

I. Introduction

A. Witness Qualifications

Q. Please state your name, business address, and job title.

A. My name is Daniel Ashbaugh. My business address is 527 East Capitol Avenue, Springfield, Illinois 62701. I am employed by the Illinois Commerce Commission ("ICC" or "Commission") as an Electrical Engineer in the Public Utilities Bureau's Integrated Distribution Planning Division.

Q. What are your responsibilities within the Commission's Integrated Distribution Planning Division?

A. I review and analyze engineering issues related to the regulation of electric distribution companies and provide expert witness testimony on engineering-related issues. I develop data requests, identify issues requiring further review, and develop recommendations, as appropriate.

Q. Please describe your educational background.

A. I hold a Bachelor of Science and Master of Science in Electrical Engineering from Southern Illinois University Edwardsville. I also hold a Master of Accountancy and Juris Doctorate from Southern Illinois University Carbondale.

B. Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to address Commonwealth Edison Company's ("ComEd" or the "Company") Verified Petition and supporting testimony, submitted on May 21, 2025, under Section 16-108.18(e) of the Public

Utilities Act ("Act"), 220 ILCS 5 *et. seq*. My testimony focuses on two subject areas: power quality ("PQ") and net benefits for Performance Metrics ("PM"): 1 and 2.

Q. Are you offering any legal opinions in your direct testimony?

A. No, I am not. While I may offer my understanding of certain provisions of the Act, none of my testimony offers any legal opinion.

C. <u>Attachments</u>

Q. Are you sponsoring any Exhibits with your testimony?

A. Yes, the following Exhibits are attached to my testimony:

Staff Exhibit 4.01	ComEd Response to Staff DR DLA 1.03

D. <u>Summary of Conclusions and Recommendations</u>

Q. What are your conclusions and recommendations regarding ComEd's power quality reporting?

A. I recommend the Commission:

1. Mandate an Interim PQ Tracking Metric (starting in 2028). ComEd should begin reporting annually in its tracking metrics report, feeder-level counts and durations of voltage and Total Harmonic Distortion ("THD") excursions for circuits monitored using existing Advanced Distribution Management System ("ADMS"), SCADA and PMU infrastructure, as well as feeders that are (i) managed by a Distributed Energy Resource Management System ("DERMS"), (ii) equipped with power quality monitoring devices, or (iii) selectively assessed using manually triggered Advanced Metering Infrastructure ("AMI") voltage or harmonic measurements.
2. Require a PQ Performance Metric (in next Section 16-108.18 filing). ComEd should consider proposing a PQ Performance Metric in its next performance

metrics docket. The metric should quantify the frequency and severity of voltage and harmonic excursions, consistent with ANSI C84.1 and IEEE 1547-2018, to enable year-over-year trend verification and net-benefits analysis under Section 16-108.18(e)(2)(F).

Q. What are your conclusions and recommendations regarding ComEd's net benefits analysis?

A. I recommend the Commission decline to find that ComEd's proposed Performance Metrics 1 and 2 satisfy the net benefits requirement of Section 16-108.18(e)(2)(F). ComEd did not provide a complete net-benefits analysis, omitting both cost estimates and disaggregated benefit calculations, for individual submetrics. Furthermore, ComEd's reported Benefit–Cost Ratios ("BCR") rely on unadjusted ICE Calculator results that are not scaled to reflect Illinois-specific reliability needs or cost levels. As required under the Grid Plan Final Order, utilities must "right-size" reliability-related investments. Commonwealth Edison Co., ICC Final Order, Docket Nos. 22-0486/23-0055/24-0181 (Cons.), 276-277 (Dec. 19, 2024) ("RGP FO").

II. Power Quality

A. What is Power Quality

Q. In plain terms, what is "power quality"?

A. Power quality describes how clean and stable the electric voltage and current are once the power is flowing. For instance, good PQ means the voltage stays within the American Standards Institute ("ANSI") limits (as defined in ANSI C84.1-2020), and the waveforms exhibit minimal distortion (as required under IEEE Standard

519-2014). Within these limits, lights do not flicker, motors run cool, and sensitive electronics operate safely. Poor PQ, on the other hand, can cause dimming lights, buzzing or equipment, premature device failure, and wasted energy.

Q. Why does PQ matter to customers and the grid?

A. PQ reflects the performance of the electric grid during normal operation—when the lights are still on. While reliability metrics like SAIDI and SAIFI capture outages, PQ metrics track disturbances such as momentary voltage sags, harmonic distortion, and flicker. PQ affects both customer experience and grid efficiency.

Q. What does Section 16-108.18(e) of the Act say about PQ improvement?

A. Section 16-108.18(e)(2)(A)(i) requires that the Commission approve a suite of performance metrics including at least one metric that is "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." 220 ILCS 5/16-108.18(e)(2)(A)(i) (emphasis added).

B. <u>Current Tracking of Power Quality</u>

Q. How is power quality typically measured on electric distribution systems?

A. Power quality is typically measured using specialized monitoring equipment—such as AMI voltage channels, feeder-head SCADA sensors, and distribution Phasor Measurement Units ("PMUs")—that can detect deviations in voltage, frequency, harmonics, and phase angle in real time. These devices log high-resolution electrical data and compare it against standards like ANSI C84.1 (for steady-state voltage limits), IEEE 519-2014 (which defines system-level harmonic distortion limits at the point of common coupling) and IEEE 1547-2018 (which governs DER behavior, including voltage ride-through and harmonic emissions from inverter-based resources).

Q. Is power quality directly measured under ComEd's proposed metrics?

A. No. While improvements in resilience and reliability may lead to better power quality, ComEd's proposed metrics are not designed to directly measure improvements in power quality. Resilience and reliability metrics track the frequency and duration of sustained outages, not the quality of power during normal operation. Power quality refers to voltage stability, harmonic distortion, flicker, and phase imbalance—all of which can affect equipment performance even when the lights are on.

Q. Why must ComEd establish baseline and trend data for PQ?

A. In the absence of baseline and trend data, the Commission cannot verify whether improvements in PQ have materialized after implementation of the performance metrics. Without structured PQ measurement and reporting, there is no mechanism for retrospective validation and no basis for recalibrating incentives.

Q. Which engineering standards establish how power quality should be measured?

A. The key standards are from the Institute of Electrical and Electronics Engineers ("IEEE") and are as follows:

- IEEE 1159-2019: Defines and classifies PQ disturbances such as voltage sags, swells, interruptions, transients, harmonics, and flicker. It specifies monitoring practices, event thresholds, and cycle-level sampling (typically ¼ to ½ cycle resolution).

- IEEE 1547-2018: Establishes interconnection and performance standards for Distributed Energy Resources ("DERs"), including continuous monitoring of voltage, frequency, and reactive power to verify ride-through, volt/VAR, and frequency response behaviors.
- IEEE C37.118-2011: Specifies data formats, performance requirements, and accuracy classes for phasor measurement units ("PMUs"), enabling high-speed, time-aligned measurements of voltage, current, phase angle, and frequency.
- IEEE 1459-2010: Defines how to calculate active, reactive, apparent, and distortion power in three-phase systems, providing a consistent basis for measuring power factor and energy under PQ-distorted conditions.

C. <u>Interim Tracking of Power Quality</u>

Q. Why is interim tracking of voltage and harmonic excursions necessary before the next performance-metrics docket?

A. Interim tracking is necessary because PQ issues—such as voltage excursions and harmonic distortion—pose risks to customer equipment and grid efficiency, yet ComEd currently lacks a consistent, system-wide framework to monitor these issues. As shown in ComEd's response to Staff data request DLA 1.03, the Company's existing infrastructure—such as AMI meters, SCADA and PMUs—either does not monitor certain PQ parameters (e.g., total harmonic distortion, voltage imbalance, flicker) or does so on a limited, ad hoc, or an unscheduled basis. (Staff Ex. 4.01.) For example, ComEd reports having only a single PQ meter deployed on one 34kV feeder and acknowledges that most SCADA and PMU devices do not measure THD. Id. AMI meters can retrieve harmonic data only through manual triggering, and the resulting measurements do not conform to IEEE standards for duration or sampling resolution. (Id.; IEEE Standard 1159-2019.) In short, ComEd's current monitoring capabilities are fragmented and fall short of IEEE 1159's recommended practices for power quality event detection, which call for continuous or event-triggered monitoring with high temporal resolution (typically 1/4 to 1/2 cycle sampling) at representative points along feeders. (IEEE Standard 1159-2019.) Requiring ComEd to begin interim tracking of ANSI C84.1 voltage excursions and IEEE 1547-2018 total harmonic distortion ("THD") violations on DERMS-managed, PQ-monitored feeders, and manually triggered AMI voltage or harmonic measurements—by Q1 2028 will provide a consistent baseline under real operating conditions. (IEEE Standard 1547-2018.) This data will enable the Commission and stakeholders to evaluate grid performance trends and lay the groundwork for a formal PQ Performance Metric in the next performance-metrics docket.

Q. What is ANSI C84.1 and why is it important for PQ tracking?

A. ANSI C84.1 defines acceptable steady-state voltage limits for electric power systems. It includes "Range A" (the preferred voltage band for normal operation) and "Range B" (an allowable band for short-duration excursions).[1] These thresholds are widely used by utilities to protect customer equipment—such as motors, lighting, and electronics—from damage due to sustained over- or under-

[1] https://www.pge.com/assets/pge/docs/contact-us/report-an-issue/Voltage_Tolerance.pdf

voltage conditions. Tracking violations of these limits is critical to identifying voltage instability on feeders and informing voltage-control investments.

Q. What is IEEE 1547-2018 and how does it relate to DERMS and harmonic tracking?

A. IEEE 1547-2018 governs the interconnection and operation of distributed energy resources (DERs) with the electric grid.[2] It requires DERs to continuously monitor voltage and THD at the point of common coupling and to comply with ride-through and volt-VAR response requirements. These provisions ensure that inverter-based resources contribute to—rather than disrupt—grid stability. Tracking THD excursions under IEEE 1547-2018 helps confirm whether DERMS is enabling compliant and reliable integration of inverter-based technologies.

D. Power Quality Metric for the Next Performance Metric Docket

Q. What should a power quality performance metric include in ComEd's next filing under Section 16-108.18?

A. ComEd should consider proposing a performance index measuring the frequency and severity of voltage and THD excursions on DERMS-managed feeders. This metric should align with ANSI C84.1 and IEEE 1547-2018 thresholds and be structured to allow net-benefit evaluation as required by Section 16-108.18(e)(2)(F). Without such a metric, ComEd cannot be held accountable for actual PQ improvements or demonstrate that grid investments are delivering tangible customer benefits in the form of improved PQ.

[2] https://docs.nrel.gov/docs/fy20osti/75436.pdf

E. Conclusion and Recommendations

Q. What actions do you recommend the Commission take with regard to power quality?

A. I recommend the Commission take the following actions to ensure ComEd's PQ performance is transparent, measurable, and aligned with statutory requirements:

1. Require ComEd to begin systematically tracking and reporting annually in its tracking metrics report the number and duration of ANSI C84.1 voltage excursions and IEEE 1547-2018 total harmonic distortion ("THD") in its tracking metrics report. Tracking should utilize existing Advanced Distribution Management System ("ADMS"), SCADA, and PMU infrastructure, as well as feeders that are (i) managed by a Distributed Energy Resource Management System ("DERMS"), (ii) equipped with power quality monitoring devices, or (iii) selectively assessed using manually triggered Advanced Metering Infrastructure ("AMI") voltage or harmonic measurements. While ComEd currently lacks full system-wide monitoring capability, this targeted approach can still provide meaningful baseline data from representative areas of the distribution system.

2. Direct ComEd to consider including a PQ Performance Metric in ComEd's next Performance Metrics filing. The performance metric should quantify the frequency and severity of voltage and THD violations using established standards—ANSI C84.1 for voltage and IEEE 1547-2018 for harmonics—to enable year-over-year trend verification and net-benefits analysis under Section 16-108.18(e)(2)(F).

III. Net Benefits Analysis

A. ComEd's Net-Benefits Methodology for Performance Metrics 1 and 2

Q. What is the Commission's cost-effectiveness framework for evaluating performance metrics under Section 16-108.18(e)(2)(F)?

A. Section 16-108.18(e)(2)(F) of the Act requires the Commission to approve only those performance metrics that are "cost-effective" and provide "net benefits" to customers and society. In Docket 22-0067, the Commission acknowledged that Section 16-108.18(e)(2)(F) does not require a cost-benefit analysis but found that such an analysis, where feasible, would aid in evaluating whether a proposed performance metric produces net benefits. (Commonwealth Edison Co., ICC Final Order, Docket No. 22-0067, 69 (September 27, 2023) ("PM Plan 1 FO").) The Commission emphasized that it—not the utility—is statutorily required to develop a net-benefit methodology incorporating customer and societal costs and benefits and the effect on delivery rates. Id. at 69. However, the Commission found it logical and necessary for utilities proposing performance metrics to supply at least a preliminary net-benefit methodology for the Commission's consideration. Id. The Commission also noted that future proceedings would likely yield improved information and methodologies. Id.

Q. What is ComEd's proposed Performance Metric 1 ("PM1")?

A. ComEd's proposed PM 1 is titled Reliability and Resiliency.[3] It is designed to reduce the duration of outages across the system and improve reliability for

[3] My testimony is limited to an examination of net benefits of PM1. Staff witness Balogun discusses in detail ComEd's proposed performance metrics 1 and 2 in Staff Exhibit. 3.0.

customers most affected by frequent or prolonged outages. PM1 consists of two submetrics:

1. Submetric 1 – System SAIDI Excluding EWEDs: This submetric measures the average duration of service interruptions system-wide, excluding Events With Extreme Weather Designation ("EWEDs"). (ComEd Ex. 1.01, 2.)
2. Submetric 2 – EWED Resiliency: This submetric is designed to measure resiliency as reflected in the system's ability to withstand and recover from EWEDs. Id. at 4.

Q. How does ComEd demonstrate net benefits for PM 1?

A. ComEd asserts that its proposed PM 1 (Reliability and Resiliency) will provide value by reducing outage durations and frequencies for customers. (ComEd Ex. 2.0, 4-21.) To support this claim, ComEd references the use of the Department of Energy's Interruption Cost Estimate ("ICE") Calculator 2.0 and the Power Outage Economic Tool ("POET") to estimate avoided outage costs. Id. at 14. ICE Calculator 2.0 is designed to estimate direct customer costs from interruptions up to 24 hours in duration, while POET focuses on longer-duration outages, including indirect and societal impacts. Id. at 11.

Q. How does ComEd demonstrate net benefits for PM1 (Reliability and Resiliency)?

A. For PM 1, ComEd provides a single monetized benefit estimate using ICE Calculator 2.0. (ComEd Ex. 2.0, 11-12.) ComEd claims that achieving the maximum performance incentive each year would reduce SAIDI Excluding EWEDs by 4 minutes annually, which it equates to a 12-minute annual reduction in All-In SAIDI for ICE modeling purposes. Id. at 12. Based on this assumption, ComEd estimates annual customer benefits of approximately $67.5 million, or $1.69 billion over a 25-year investment horizon. Id. at 12.

Moreover, ComEd does not identify the capital or O&M costs associated with achieving the PM 1 targets. It provides no BCR, no net present value calculation, and no alignment between benefit duration and the four-year metric cycle. As such, ComEd fails to demonstrate that PM1 is cost-effective or yields net benefits as required by Section 16-108.18(e)(2)(F).

Q. What is ComEd's proposed Performance Metric 2 ("PM 2")?

A. ComEd's proposed Performance Metric 2 ("PM2") is titled Environmental Justice ("EJ") and R3 Reliability . (ComEd Ex. 2.0, 3.) It is designed to improve reliability outcomes for customers in historically underserved areas by measuring and incentivizing reductions in both the frequency and duration of outages. PM 2 includes four submetrics:

1. SAIDI Excluding EWEDs in EJ and R3 Communities: measuring average outage duration per customer;
2. SAIFI Excluding EWEDs in EJ and R3 Communities: measuring average number of interruptions per customer;
3. CEMI3R3: percentage of EJ and R3 customers experiencing three or more interruptions in a year; and
4. CELID8R3: percentage of EJ and R3 customers experiencing any single interruption lasting eight or more hours.

Id. at 12-15.

Q. How does ComEd demonstrate net benefits for PM 2 (Reliability in EJ and R3 Communities)?

A. ComEd states that the benefits of PM 2, Submetric 1 (SAIDI Excluding EWEDs in EJ and R3 communities) and Submetric 2 (SAIFI Excluding EWEDs in EJ and R3 communities) can be quantified using the ICE Calculator 2.0. (ComEd Ex. 2.0, 19-20.) However, ComEd acknowledges that the ICE benefit calculated for EJ and R3 communities is already included in the overall system SAIDI benefit and is therefore not additive Id. at 19., which Staff interprets to mean that that the outage cost savings calculated for PM 2 (EJ and R3 communities) are already included within the broader system-wide benefit calculated for Metric 1 (total SAIDI).

For Submetrics 3 (CEMI3R3) and 4 (CELID8R3), ComEd asserts that the reduction in the number of customers impacted by repeat or long-duration outages creates inherently quantifiable impacts and potential qualitative benefits—such as improved health, economic, and public safety outcomes—but does not provide a monetized estimate for these effects. Id. at 20.

For Submetrics 1 through 4, ComEd does not present any quantified dollar value of benefits for PM 2 in the evidentiary record. Id. Furthermore, ComEd does not identify the capital or O&M, or costs required to meet its targets. As such, ComEd fails to present a complete net-benefit analysis for PM 2 as required under Section 16-108.18(e)(2)(F).

B. Right-Sizing of Reliability-Related Investments

Q. What is "right-sizing" and how does it relate to the Performance Metrics docket?

A. Right-sizing refers to the Commission's directive that ComEd develop a structured framework to appropriately scale the level and pace of its reliability-related investments, in conjunction with—but not dictated solely by—the results of the ICE Calculator. RGP FO at 277. As the Commission explained, "in isolation, the ICE calculator does not address the magnitude of reliability-related investments ComEd should pursue." Id.

The Commission expressed concern that ComEd's use of the ICE Calculator may not fully or accurately identify the scope of benefits and timing associated with specific investments. Id. The Order emphasized that while cost-effectiveness is important, it is not the only statutory requirement; the Company's grid plan "must also be designed to be affordable and equitable." Id. Grid plans must avoid premature or costly reliability investments that "do not outweigh the costs to achieve them." Id.

Accordingly, the Commission directed ComEd to work with stakeholders and Ameren to develop a framework that better aligns ICE Calculator outputs with Illinois-specific benefits. Id. This framework must incorporate state- or utility-specific data and balance monetized outage-avoidance benefits with customer rate impacts, system needs, and statutory equity goals. Id.

This requirement directly relates to the performance metrics docket under Section 16-108.18(e), which mandates that each approved performance metric deliver verifiable net benefits to customers and society. PM Plan 1 FO, 43-44. Without a right-sizing framework, utilities could rely on generic ICE inputs to inflate BCRs and justify excessive basis-point incentives. Right-sizing ensures that both the metric design and associated investment levels are transparent, calibrated, and proportionate.

Q. Has ComEd yet complied with the right-sizing directive?

A. No. The Commission directed ComEd to work with stakeholders and Ameren to identify state- and utility-specific considerations to better align ICE Calculator 2.0 outputs with expected benefits to customers, and to develop "a framework the Companies will use to support the level of reliability investments proposed in their next Grid Plans." RGP FO at 277. However, to my knowledge, a framework has not been proposed.

ComEd's May 21, 2025 filings present no evidence of such calibration—no modified ICE parameters, no adjusted investment levels, and no demonstration that performance targets were "right-sized" consistent with the Commission's directive.

Q. What risks arise when ICE results are not right-sized, and how do they affect incentive payouts?

A. When ICE results are not right-sized, several risks arise that directly affect the credibility of cost-benefit estimates and the fairness of incentive payouts under Section 16-108.18(e). Without tailoring the ICE Calculator's inputs to Illinois-specific conditions—such as regional reliability baselines, customer outage sensitivities, and realistic investment scopes—ComEd may overstate the monetized benefits associated with a given performance metric. This can artificially inflate the BCRs and make relatively modest reliability improvements appear disproportionately valuable. Such inflated BCRs could, in turn, be used to justify excessive basis-point incentive awards that are not commensurate with the actual investment risk or customer benefit. As the Commission explained, "consideration of customer rate impact and affordability requires limits on the level of appropriate improvement" to avoid reliability investments that "do not outweigh the costs to achieve them." RGP FO 276.

C. Conclusions and Recommendations

Q. Should the Commission rely on ComEd's reported BCRs to justify PM 1 and PM 2?

A. No. The Commission should not rely on ComEd's analysis to justify performance incentives for PM1 and PM2 because ComEd has not provided any BCRs, nor has it submitted a complete or compliant net-benefits analysis under Section 16-108.18(e)(2)(F).

First, for PM1, ComEd offers a single monetized benefit estimate derived from unadjusted ICE Calculator 2.0 inputs, assuming a 12-minute annual SAIDI reduction. (ComEd Ex. 2.0, 11–21.) However, it does not identify the associated capital or O&M costs, nor does it calculate a BCR, net present value, or cost-effectiveness ratio aligned to the four-year performance metric cycle. Id. For PM2, ComEd presents no monetized benefit estimates at all—either from ICE or POET—and again provides no cost data. Id. In the absence of these essential components, ComEd has not demonstrated that either metric is cost-effective or produces net benefits, as required by Section 16-108.18(e)(2)(F) of the Act.

Second, ComEd has not complied with the Commission's directive to right-size ICE outputs using Illinois- and utility-specific considerations. (RGP FO at 276-277.)

In the RGP FO, the Commission agreed with Staff that "the ICE calculator may not accurately identify the scope of benefits and timing associated with a specific investment," and emphasized that "in isolation, the ICE calculator does not address the magnitude of reliability-related investments ComEd should pursue." Id. at 276. The Commission further explained that "consideration of customer rate impact and affordability requires limits on the level of appropriate improvement," and directed ComEd to work with Ameren and stakeholders to develop a right-sizing framework that applies Illinois-specific adjustments to ICE outputs—not just rely on unmodified national assumptions. Id. at 276.

The Commission also approved interim use of ICE Calculator 2.0 only in conjunction with this calibrated framework and directed ComEd to ultimately develop a utility-specific outage cost tool to improve precision and transparency. Id. at 276-277.

As of its May 21, 2025, petition, ComEd has not demonstrated compliance with these directives. There is no evidence of any adjusted ICE inputs, no alignment of outage assumptions with Illinois-specific data, and no application of the stakeholder-informed right-sizing framework required to contextualize ICE results.

Accordingly, I recommend that the Commission decline to find PM 1 and PM 2 satisfy the net-benefit requirement of Section 16-108.18(e)(2)(F). Any approval of these metrics should be conditioned on ComEd completing and applying the ICE output right-sizing framework in a supplemental filing or compliance phase as required under the Grid Plan Order.

IV. Conclusion

Q. Does this conclude your prepared direct testimony?

A. Yes.

ICC Docket No. 25-0514

**Commonwealth Edison Company's Response to
Illinois Commerce Commission ("STAFF") Data Requests
DLA 1.01 – DLA 1.14
Date Received: June 13, 2025
Date Served: June 27, 2025**

REQUEST NO. DLA 1.03:

Populate the supplied Attachment A or provide any existing table/export that contains the same data fields (parameter measured, device class, sampling interval, feeder coverage). If ComEd supplies its own export, Staff will transpose the data.

Attachment A – Staff PQ Parameter Matrix

Q Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell					
Total Harmonic Distortion (THD)					
Flicker (P_{st}*)					
Power Factor					
Transient Overvoltage					
Voltage Imbalance					
Frequency Deviation					

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.

RESPONSE:

To aid with clarity, ComEd is providing separate tables for each device type. Note that smart inverters are generally not controlled by ComEd and ComEd does not have specific fault recorders, but does use relays, which function as digital fault recorders. Unless specifically defined otherwise, terms will be interpreted based on their definitions set forth in IEEE 1159.

Table I
Attachment A – Staff PQ Parameter Matrix for PQ meters

PQ Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell	Event-Triggered	PQ Meter	256 samples/cycle	Covers one location in networked 34kV feeder	
Total Harmonic Distortion (THD)	Event-Triggered	PQ Meter	256 samples/cycle		
Flicker (P_{st}*)	Event-Triggered	PQ Meter	256 samples/cycle		
Power Factor	Not Measured by event trigger	PQ Meter	N/A		
Transient Overvoltage	Event-Triggered	PQ Meter	256 samples/cycle		
Voltage Imbalance	Event-Triggered	PQ Meter	256 samples/cycle		
Frequency Deviation	Event-Triggered	PQ Meter	256 samples/cycle		

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.

Table II
Attachment A – Staff PQ Parameter Matrix for SCADA

PQ Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell	Not Measured	SCADA	N/A	Feeder Head, Distribution Automation Devices, Capacitor banks, voltage regulators, Bus group	PQ parameters not natively measured or monitored on SCADA, Voltage, Current, Power (kW, kVAR, kVA) are typically measured
Total Harmonic Distortion (THD)	Not Measured	SCADA	N/A		
Flicker (P_{st}*)	Not Measured	SCADA	N/A		
Power Factor	Not Measured directly. kVAR is measured	SCADA	30s to 2m		
Transient Overvoltage	Not Measured	SCADA	N/A		
Voltage Imbalance	Not Measured	SCADA	N/A		
Frequency Deviation	Not Measured	SCADA	N/A		

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.

Table III
Attachment A – Staff PQ Parameter Matrix for PMU

PQ Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell	Not Measured	PMU	N/A	25 micro PMUs in Bronzeville for DLSE. 33 substations with PMUs	PQ parameters not natively measured by PMUs. 3 voltage and 3 current channels continuously streamed 60 samples per second.
Total Harmonic Distortion (THD)	Not Measured	PMU	N/A		
Flicker (P_{st}*)	Not Measured	PMU	N/A		
Power Factor	Not Measured	PMU	N/A		
Transient Overvoltage	Not Measured	PMU	N/A		
Voltage Imbalance	Not Measured	PMU	N/A		
Frequency Deviation	Deviation Not measured. Actual frequency Measured.	PMU	60 samples per second		

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.

Table IV
Attachment A – Staff PQ Parameter Matrix for AMI

Note: AMI meters are primarily used to monitor average voltage, current, kW, and kWh, at a 30 min interval. Two broad categories exist: I-210c for residential and kV2C for commercial customers. The table below describes the features on commercial meters.

PQ Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell	Not Measured	AMI	N/A	N/A	N/A
Total Harmonic Distortion (THD)	Not available in most meters. Adhoc capability (manual trigger) available in most 3 phase meters.	AMI	No active sampling interval	Varies feeder by feeder. Provided to most 3 phase customers	Measurement does not conform to IEEE 519/1159. Manual trigger captures <5 seconds of data. IEEE 519 requires a minimum period of 1 day for monitoring “very short term harmonics” and 7 days of data for “short term” harmonics. Similar capability exist for current (TDD)
Flicker (P_{st}*)	Not Measured	AMI	N/A	N/A	N/A
Power Factor	Adhoc	AMI	No active sampling interval	Varies feeder by feeder. Provided to most 3 phase customers	Not actively captured
Transient Overvoltage	Not Measured	AMI	N/A	N/A	N/A
Voltage Imbalance	Not Measured	AMI	N/A	N/A	N/A
Frequency Deviation	Not Measured	AMI	N/A	N/A	N/A

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.

Table V
Attachment A – Staff PQ Parameter Matrix for Relays

PQ Parameter	Measurement Status (Continuous / Event-Triggered / Ad-Hoc / Not Measured)	Device Class(es) Providing Data (SCADA, PQ Monitor, AMI, Fault Recorder, Smart Inverter)	Sampling Interval (e.g., 1 s, 15 min)	Feeder Coverage (%)	Notes / Comments
Voltage Sag / Swell	Event Based, typically up to 1 to 5 seconds. Does not conform to IEEE 1159	Relay	4/8/16/32/64/128 Samples per cycle depending on relay type and capture mode	One per feeder head with microprocessor relay. Also available in most field devices.	Devices feeding equipments with ridethrough may have larger ranges that would partially exclude the lower ranges.
Total Harmonic Distortion (THD)	Not Measured	Relay	N/A	N/A	N/A
Flicker (P_{st}*)	Not Measured	Relay	N/A	N/A	N/A
Power Factor	Not Measured	Relay	N/A	N/A	N/A
Transient Overvoltage	Event Based. May not conform to IEEE1159 depending on mode of capture and sampling rate of relay	Relay	4/8/16/32/64/128 Samples per cycle depending on relay type and capture mode	One per feeder head with microprocessor relay. Also available in most field devices.	Devices feeding equipments with ridethrough may have larger ranges that would partially exclude the lower ranges.
Voltage Imbalance	Not Measured	Relay	N/A	N/A	N/A
Frequency Deviation	Event Based. May not conform to IEEE1159 depending on mode of capture and sampling rate of relay	Relay	4/8/16/32/64/128 Samples per cycle depending on relay type and capture mode	One per feeder head with microprocessor relay. Also available in most field devices.	Devices feeding equipments with ridethrough may have larger ranges that would partially exclude the lower ranges.

* P_{st} is the perceptibility short-term metric defined in IEC 61000-4-15. It quantifies how irritating lamp brightness fluctuations (voltage flicker) are to the human eye over a 10-minute evaluation window.