Final Report
Baseline Distribution Grid Assessment of Commonwealth Edison Company

Pursuant to Section 16-105.10
of the Illinois Public Utilities Act

Presented to:
The Illinois Commerce Commission

Presented by:
The Liberty Consulting Group

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1451 Quentin Rd Suite 400
#343
Lebanon, PA 17042

admin@libertyconsultinggroup.com

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I. Introduction and Background

The Illinois Commerce Commission (ICC) sought to hire a consultant, or consultants, to perform independent audits (Audits) of Commonwealth Edison Company (ComEd or the company) and Ameren Illinois Company (Ameren IL or AIC) pursuant to the requirements of the newly enacted Section 16-105.10 of the Illinois Public Utilities Act (Act), 220 ILCS 5/16-105.10. The Act required, among other things, "[p]rior to the filing of the initial Multi-Year Integrated Grid Plan described in Section 16-105.17 of this Act… an independent audit of the current state of the grid, and of the expenditures made since 2012, will need to be made" for both ComEd and AIC.

There five specific objectives set by the Act and embodied in solicitations issued by the ICC Staff in October 2021, stated as follows:

1. An assessment of the distribution grid necessary to understand the benefits of these investments to the grid and to customers and to evaluate the current condition of the distribution grid.
2. An analysis of the utility's capital projects, including but not limited to projects whose cost exceeded $2 million, placed into service in the preceding 9 years, including but not limited to, assessing the value of deploying advanced metering infrastructure to modernize and optimize the grid and deliver value to customers.
3. An analysis of the utility's initiatives to optimize the reliability and resiliency of the grid, other than through capital spending.
4. Creation of a data baseline to inform the beginning of the multi-year integrated grid planning process described in Section 16-105.17 of this Act.
5. Identification of any deficiencies in data which may impact the planning process.

The Commission selected The Liberty Consulting Group (Liberty), to perform the required audits of ComEd and of AIC. Work began in mid-October 2021 and concluded in April 2022 with the release of the report(s) to the ICC.

This report describes how the capabilities of the ComEd distribution system have changed in the past decade or so, what types and amounts of investments have driven those changes, and how capital and asset management expenditures have changed in balancing the many alternatives and needs an electricity distribution system operator faces in maintaining and improving a distribution network.

These capital and asset management expenditures have gone to placing, replacing, adding, maintaining, and operating a wide variety of equipment, systems, tools, and information capabilities. Together, the additions, replacements, and enhancements that these expenditures produced have improved the ability to get power to the network and distribute it among the system elements that serve customers, perform more reliably under normal circumstances, withstand and respond more quickly to isolated and broad-ranging outages, and provided management with a greater ability to understand and respond to changes in system status. As or more importantly, the resulting system and the ability to use it have also given customers greater ability to manage their electricity use, understand events disrupting their use and likely times for restoring it, and contribute meaningfully to assuring adequate supply in more environmentally friendly ways.

We were not asked to and do not answer the question of whether on balance, the discernible improvements we observed match in value the costs of producing them. Our mission did not include an assessment of historical performance. Planning, the driver of this engagement and the much broader efforts of which it forms a small part, concerns the future. That planning will, we acknowledge, take a painstaking ride through a mass of detail to apply any benefits this report may add in supporting efforts to prepare for the future. We have been mindful of the need to translate the information we offer into more common parlance as best we can, while reflecting the detail it takes to operate and maintain an electricity distribution system.

We have sought to provide a reasonably clear picture of how the network has changed, where expenditures have focused, how close to full penetration (as best it can be defined) certain types of enhancements have already come. We hope that our contribution will assist stakeholders by informing their judgments about where other areas have further to go as part of a more robust consideration of what new or expanded supply and supply avoidance measures can be readily accommodated, and what more needs to be done to enhance network attributes on which they place value. We consider such insights to form important bases for stakeholders performing traditional planning roles and for those undertaking new or expanded ones. At least, our goal in preparing this report has been to provide those kinds of insights to stakeholders responsible for planning the future of the network, and to allow them to mine data we have assembled (with major ComEd efforts) to support that development.

II. Approach

We have applied a straightforward approach that consisted of a series of key steps - - ones we have applied on scores of other projects requiring massive amounts of data and explanation of technical utility planning and operations matters:

- Understand the details and drivers supporting the articulated scope
- Review and assess existing documentation available to support the project
- Craft data requests to supply additional information considered central to addressing the solicitation's objectives
- Conduct interviews with ComEd staff to provide clarity or additional detail for data already submitted and/or identify and request new information
- Conduct regular project status meetings with Staff
- Create a regular channel of communication with utility personnel to ensure schedules were met, data requests were responded to in a timely fashion, interviews were scheduled at mutually convenient times, and open issues were promptly addressed
- Develop the draft report in concert with project milestones that provided for Staff and then company review of the draft for factual accuracy prior to report finalization.
- Report submittal to the ICC.

With full cooperation and support from ComEd and Staff, this report provides a robust set of data and a broad series of operations about how the distribution system has changed in the last decade, how emphasis on its components have shifted, where dollars went, and what changes in network capabilities and performance quality have resulted. We also examined, at Staff's request, and we recapitulate here ComEd's processes to date for planning the system.

We hope that this report will assist in informing discussions moving forward about changes required to accommodate the legislation's intent to increase access to, and information about, the distribution grid, provide enhanced opportunity for Distributed Energy Resource (DER) interconnection, enhance grid reliability and resiliency, and direct investment in a manner that balances many competing priorities. Regularly scheduled calls with ComEd personnel proved particularly useful in understanding interview and data response status and in offering clarity to provided data. Company personnel proved open and responsive to our needs and requests and to assisting in meeting the objectives of this engagement. We received responses to all data requests within the agreed upon two-week turnaround (extremely rare for projects on our timeline and involving the large amounts data needed here), and interviews were scheduled in a timely fashion. We encountered no inability to secure the full scope of the information we requested from the company.

Staff data requests issued prior to the start of our work produced a great quantity of information that assisted our start-up efforts in mid-October 2021. We examined and analyzed that information to determine what else we would need to complete our engagement. We developed additional data requests over the course of the assignment, securing information to fill gaps and address additional subject areas. A series of interviews assisted in defining what we needed, interpreting what the company provided, and assisting in our analysis of a growing database encompassing network components as they changed over a decade, where management made investments and operations and maintenance (O&M) expenditures and by how much, and what those expenditures produced in terms of network configuration, capability, and condition.

Our scope included an identification of "…any deficiencies in data which may impact the planning process." We encountered no data gaps that impeded our ability to describe how network configuration, capability, and condition have changed in the past decade, what benefits those changes have produced, or in how management has conducted planning processes. The planning process soon to follow may well identify future data needs, but we found no information barriers to providing a reasonably complete picture of what the network can do today or in permitting stakeholders to determine what may require change in the future.

We have structured the report in a manner that provides a clear, although technical at times, focused review of the areas covered in the solicitation. The following chapters comprise the balance of the report:

- Chapter III: Electric System Overview
- Chapter IV: System Description and Configuration
- Chapter V: Capital Investment and O&M Spending
- Chapter VI: Distribution System Condition
- Chapter VII: Distribution System Performance
- Chapter VIII: Advanced Metering Infrastructure
- Chapter IX: Distributed Energy Resources
- Chapter X: Distribution System Planning
- Chapter XI: Database

III. Electric System Overview

A. Introduction

The National Academy of Sciences ranks the electrification of America as one of the greatest engineering achievements of the 20th century, along with, or arguably ahead of, the internet, automobiles, computers, radio and television, and other life-changing technologies. A subjective assessment to be sure, but representative of technically informed opinions and reflective of the integral nature of the electric grid to daily life. Whether flicking a light switch, powering the internet, charging a phone, running an air conditioner, or myriads of other quotidian functions, electricity allows it to happen. Across the country we have come to expect electricity to be virtually everywhere, always on, highly reliable (notwithstanding the inevitable, but relatively infrequent interruptions), and very safe when used properly. We generally take the availability of a dependable supply of electricity as a given. We notice only its absence (or when we receive a monthly bill). But this familiarity belies the complex and highly interrelated components of the "machine," built up slowly, conservatively, and inexorably over the last hundred years.

Material changes to electric grid infrastructure and operations occur slowly. Given the grid's critical importance to economic and societal well-being, changes that affect electricity use, in the form of new technologies or network infrastructure and configuration, tend to evolve more than transform, require substantial pre-adoption testing and validation, and generally come when new products or technologies reach a reasonably mature stage in their life cycles. A conservative, safety and reliability focused management approach has prevailed. Naturally, though, some companies manage change more effectively and efficiently than others. Moreover, interest has grown in many regions of the country in accelerating changes in network capability as information availability has influenced customer engagement in managing their electricity use, as value on reliability and prompt service restoration has heightened, as the range of new sources and methods of adding and avoiding the need for supply has expanded, and as interest in affordability and environmental stewardship have grown as well.

A high-level understanding of electric grid architecture, its salient characteristics, and the underlying key systems and sub-systems provides a fuller understanding, particularly for the non-technical reader, of the information, and its importance, gathered during the baseline grid assessment and what future changes to the design of the "machine" might entail.

B. Grid Overview

Electric delivery systems transport electricity from production facilities to consumers. A simplified model or analogy can illustrate the major sub-systems that provide the linkage between system endpoints, *i.e.*, energy production and end-use consumption. Production of power and energy falls to others, not ComEd, but remains the originating source, increasingly supplemented by new sources either of providing it or avoiding the need to provide it. A simplified "electricity delivery chain" model assists in the understanding of regional differences and utility investment strategies. The supply chain consists of a series of elements; production (as offset by important avoidance measures), transmission, transformation, distribution, and consumption.

Transmission lines transmit power to transmission and distribution substations generally somewhat remote from end users, employing voltages designed to reduce inevitable losses of electricity. At those substations, transformation to lower voltage levels permits power distribution to lower voltage circuits, more numerous as the system reaches out to the full population of end users. ComEd's system employs High Voltage Distribution (HVD) systems at voltages from 69kV to 345kV. ComEd's substations transform a higher transmission voltage to a lower transmission voltage or to distribution voltage levels at 34kV or less. Typical distribution circuit configurations resemble the main trunk and branches of a tree, distributing power to distribution transformers, either pole top, pad mount, or underground, which then transform electricity to customer voltages for consumption, the last step in the chain.

Electric utility delivery system reliability and resiliency depends on system capability - - a function of underlying design, quality of construction, and asset maintenance of sound condition. It takes large capital investment and comprehensive asset management programs, which require major capital and O&M investment expenditures made pursuant to carefully constructed strategies that consider all contributors to capability. System operability also contributes to or can sometimes detract from capability. Investment in system monitoring and control comprises principal drivers of operability by expanding real time operator knowledge of conditions and threats, and, particularly in more recent years in the industry, the ability to perform remote operations to address them. Utilities used numerous system enhancement strategies in the past as well as in ongoing initiatives to improve their delivery system capability.

Exposure and redundancy comprise two key system reliability characteristics. Exposure (or risk of adverse conditions or events) increases with the number of components (*e.g.*, asset counts and circuit miles). Overhead systems have more exposure than underground systems. Providing redundancy reduces exposure; fully redundant configurations can preclude a loss of service from a single component failure or provide a standby source to avoid outages following such failure. Understanding and measuring exposure and providing an affordable level of redundancy focused on the most significant exposures comprise central elements of system design and configuration.

Affordability considerations make it feasible to provide some but not all sub-system redundancy, and among sub-systems at some but not all locations. Each link in the chain that brings electricity to end users creates its own inherent exposures, based on its role, configuration, and the environment in which it operates. Common causes, which affect different equipment and locations differently, include component failures and environmental hazards (*e.g.*, equipment failure, trees, weather, animals, cars).

Electricity use and the numbers using it have expanded vastly over the history of system development, although usage growth has moderated in more recent years. As that growth has occurred, electric system design and configuration made increased use of higher voltage levels. That development has proven uneven across the country, given different growth patterns and individual company design strategies and preferences. Development has produced different voltages within common functional subsystems, such as distribution circuits. Delivery chains for different types of customers served by the same utility also differ. For example, many utilities use the term "sub-transmission" to describe the components linking higher voltage transmission with lower voltage distribution facilities. ComEd delivers electric service to a small number of very high-use customers (termed "high voltage") at 345kV, 138kV, and 69kV transmission voltages. It serves its remaining customers at "primary distribution voltages" at 34kV and below (predominately at 12kV).

C. Key System Characteristics

Five particularly important characteristics drive electric delivery system capability:

- Exposure mitigation
- Redundancy
- Transfer capability
- System monitoring
- Circuit Auto-Response.

Construction and design standards and practices, maintainability, technology, and information security have importance as well, but this chapter focuses on these five key drivers.

1. Exposure

Exposure encompasses a system's vulnerability to failure. Good measures for quantifying it multi-dimensionally do not exist, but more general, subjective means exist for describing and for comparing it among systems. Exposure has a direct connection to the number of potential asset failures (*e.g.*, asset component population, serial versus parallel configuration, maintenance cycles and work completion rates). The environment in which systems operate also affects exposure directly, making factors like weather, terrain, right-of-way access, and vegetation material. Sheer numbers of assets also affect exposure, particularly when combined with consideration of the multiple environments in which they operate in a multi-region utility. For example, circuit miles, an industry method to measure circuit length, and the number of substations, by asset population or by landmass footprint of facilities, have a strong bearing on the risks to which utility facilities face exposure and to what degree. Customer numbers and types, which also can differ markedly across a utility's service territory, have a bearing on the types and extents of exposure.

Exposure in electric delivery systems increases the further one moves from supply sources toward end-use and the "downstream" numbers of grid components increase. Assessing exposure requires consideration of all the factors that create risk. For example, ComEd's electric grid, by most measures, has proportionally less exposure to weather than does AIC's electric grid due to greater use of underground facilities, which affords greater protection from environmental elements, and a smaller amount percentage of rural overhead circuits. Despite this differential, more than half of ComEd's circuit mileage consists of overhead circuits, largely exposed to environmental elements.

2. Redundancy

Providing electric system redundancy generally comes from configurations that offer alternate supply or parallel delivery paths to groups of end users. Delivery systems typically apply more significant redundancy at the top, or transmission level, with redundancy decreasing in downstream system components or subsystems. Adding redundancy mitigates exposure to the consequences of failures of single components. "Loop" and "ring" configurations offer multiple supply paths to eliminate outage risks of serial configurations.

A principal means of providing redundancy involves the provision of an alternate source following isolation of the segment affected by failure. Both manual and automatic (the latter increasing in deployment across the industry more recently) reconfiguration allow a switch to an alternate source. Automatic and manual circuit ties provide operational flexibility to maintain service in both emergencies and for planned maintenance outages.

Reliability mitigates exposure overall but adds another risk - - parallel component failures and added interaction complexity - - for electricity delivery and for distributed generation. Utilities add protection requirements to ensure the safety and security of the grid and, as necessary, interconnected Distributed Energy Resource systems (DER).

3. Transfer Capability

Transfer capability measures the ability of systems, circuits, or equipment to deliver energy. Generally, for electric delivery systems, the voltage of subsystems decreases from top to bottom. Over time, utility systems have increased the voltage of lines and circuits as the delivery systems expanded and with the advent of interconnected transmission systems. Higher voltage adds efficiency by employing greater power transmission capability with lower levels of line loss across the greater distances more typical of higher voltage circuits.

Transfer capability has a reasonably direct relation to exposure. First, for example, circuits with higher transfer capability generally mean fewer numbers of end-use customers subject to outage. Second, higher voltage circuits typically have lower risk of failure, given their generally fewer components and comparatively more robust design. Third, the combination of the much higher customer consequence of their failure with a lower chance of failure, leads to employment of redundant configurations more frequently than for higher risk but lower consequence single failure locations at the downstream end.

4. System Monitoring

System monitoring comprises the systems, tools, resources, and activities by which operators monitor system status. As compared with distribution sub-systems, transmission, substation, and sub-transmission sub-systems typically employ more extensive and sophisticated monitoring. System operators need to maintain visibility on and knowledge of system conditions to give them the situational awareness to anticipate actions to prevent, mitigate, and respond to component failures. For many years, electric utilities have employed an increasing range of strategies and methods to enhance situational awareness through monitoring. Significant technology advances have permitted utilities to augment monitoring at the distribution circuit level and below. Even as far as those advancements have gone, monitoring capability becomes increasingly important as grids decentralize and come to rely on more distributed assets, which bring increased exposure as a cost of the benefits they introduce.

a. Substation Monitoring

Substations create a node at which line and circuit sub-systems intersect as they enter and exit. The classic example has transmission lines entering and distribution circuits leaving. Substation monitoring uses technology called System Control and Data Acquisition (SCADA). SCADA provides the centralized system operator remote monitoring of three functions: equipment control, metering, and status (alarms) - permitting situational awareness at the substation. SCADA permits quick preventive and corrective control actions (often on an automated basis) that recognize adverse configurations, adjust the configuration for system conditions, and restore power flows on the occurrence of interruptions

b. Protective Relays

Relaying equipment in substations protect them and interconnected equipment (*e.g.*, transmission or distribution circuits, transformers, breakers, capacitors, inductors, and buses). This protective relaying equipment groups assets functionally by fault-interrupting devices, which include circuit breakers, reclosers, and fuses, for example. Such devices and the protective relaying equipment function as a group to isolate faults from the system safely, securely, and dependably.

Providing protective relaying generally requires a system comprised of a number of relaying components. Generally, a group of relays protect an asset, *e.g.*, lines, circuits, or equipment. Each grouping has components that sense system power conditions and compare those conditions to a design threshold setting. Sensor readings above or below set limits cause the activation of relays that trip the interrupting device to isolate failures to contain their system effects.

Electro-mechanical and solid-state relays used to represent state of the art technology. Recent technological advances have allowed increasing use of micro-processor-based-relays. This current generation of relays enhances remote monitoring capability and improves reliability, reducing maintenance requirements at the same time. These enhanced monitoring capabilities allow remote determination of distance to a fault, which reduces field crew time to locate faults, clear them, and restore any service interrupted.

5. Circuit Auto-Response Capability

Newer technology not only enhances the ability to monitor conditions but also to correct adverse ones, in many cases through auto-response capability. Auto response permits systems to transfer to alternate power sources without the time and effort of crew dispatch, preventing interruptions altogether for some customers or at least minimizing it greatly. Technological advances have produced many types of and greater sophistication in auto response. Utilities have generally made greater use of auto response on higher voltage subsystems (transmission) than on the lower voltage systems closer to customers (*e.g.*, distribution substations and circuits). Adding auto-response capability to distribution circuits becomes increasingly expensive, given the comparatively large number of assets and the lesser redundancy their configurations typically employ.

a. Sectionalizing Schemes

Circuit sectionalizing schemes offer another commonly used means for automatic response to circuit failures. Sectionalizing splits a circuit into multiple sections and isolates the faulted section, which allows the remaining sections to continue to operate pending correction and repair of the fault. Sectionalizing reduces equipment impacts and the accompanying numbers of customers out of service due to the fault. Utilities have made increased use of distribution circuit sectionalizing, accompanying it with devices providing monitoring and auto-response capability (*e.g.*, smart reclosers, which reduce the number of customers interrupted and customer minutes of interruption).

Midpoint reclosers, another sectionalizing strategy, coordinate the protection of circuits at the substation with downstream, lateral protection devices. This configuration isolates circuit failure to its failed portion. Longer distribution circuits often require such strategies to effectively protect customers at the end of distributions circuits. For example, assume a ten-mile main circuit emanating from a distribution substation with five lateral lines, one every two miles, each serving ten customers. Without sectionalizing, a failure of the mainline at its midpoint for any reason causes all 50 customers (five laterals and ten customers per lateral) to experience an interruption. However, a mainline device permitting the sectionalization at the midpoint, will cause a failure just past the midpoint to disrupt power to only the last three laterals, reducing numbers of customers interrupted and perhaps interruption length to those that are affected. Combining reclosers functioning as midpoint sectionalizing devices with additional reclosers at “tie” points to alternate sources creates full auto-response “self-healing circuit schemes.” These schemes further minimize the number of sections out due to a single failure.

Automatic Throw Over transfer switches (ATO) provide another sectionizing and auto-response method. They generally do not employ fault interrupting devices for the bus sections, but they do provide redundancy through an open tie switch to an alternate source, for critical customers (*e.g.*, hospitals), permitting automatic source reconfiguration and customer restoration across that alternate source.

b. Self-Healing Circuit Schemes

Smart Grid self-healing-schemes offer a more sophisticated circuit sectionalizing scheme that automatically reconfigures pairs of teamed-circuits. Self-healing schemes provide redundancy and configuration monitoring to reduce the number of customers interrupted and customer minutes of interruption. Self-healing-schemes automatically identify failures, isolate faulted sections, and reconfigure the team of circuits to restore all but the failed section.

c. Smart Device Monitoring of Circuit Laterals

The typical distribution circuit sub-system’s tree-like configuration consists of a mainline using a 3-phase configuration from which many laterals (or taps) branch. The laterals may use 3-, 2-, or 1-phase configuration. The circuit mainline emanates from a distribution substation’s interrupting device (a circuit breaker or a recloser) whose relay protection isolates the entire distribution circuit sub-system. The laterals are generally individually fused, or protected with reclosing devices, to provide fault protection to the lateral section of the circuit. These fuses or reclosing devices protect the mainline circuit from faults on the lateral circuits.

Lateral fuse protection configuration permits coordination with upstream protection, whether a mid-point recloser or substation equipment. The radial configuration of laterals produces unidirectional power flow downward from the protection device to customers. No parallel source of power exits at the end of the lateral (excluding any DER interconnection contributions).

Technology advancement has introduced smart devices that sense whether the lateral failure comprises a permanent fault (wire down) or a transient (*e.g.*, a tree branch intermittently contacting the overhead conductor). These electronic devices, although more expensive, can momentarily disconnect and reconnect for transient faults, thus avoiding sustained customer interruptions and minutes.

SCADA enabled fault indicators provide another method for augmenting monitoring for circuit laterals. Fault indicator devices use the electro-magnetic energy of the fault to “pop up” a visual indicator and have been used on utility underground construction laterals to flag which cable section has faulted. Technology has permitted the integration of SCADA monitoring to reduce the time required for isolation and repair of faulted sections.

6. *End-Use Customer Monitoring*

Automated meters that have replaced legacy analog meters provide a source of customer end-use monitoring. Utilities can ping the meter during outage restoration activities to identify those customer locations remaining out of service. This capability offers a particularly high-value use in significant weather events where multiple failures can occur in a nested fashion. Under these scenarios, for example, multiple tree-contact failures can occur simultaneously on the distribution circuit mainline and at lateral locations. Upon restoration of the mainline, laterals may still be out of service due to blown lateral fuses. Automated Metering Infrastructure (AMI) meters provide operational visibility, via pinging methods, to determine the status of remaining interrupted customers in complex failure scenarios without the need for additional customer call-in, thereby reducing customer minutes interrupted.

D. Key Concepts

Key concepts introduced in this Chapter include exposure, redundancy, and monitoring capability. Chapter VI, *Distribution System Condition*, addresses how these underlying subsystem characteristics shape utility maintenance routines, most notably their level of exposure. Chapter VII, *Distribution System Performance*, addresses how underlying system configuration characteristics of exposure, redundancy, and operability impact reliability performance metrics. Chapter X, *System Planning* addresses how system power delivery and reliability characteristics become integrated into system planning objectives for capacity, corrective maintenance, and reliability planning. Chapter V, *Capital Investment and O&M* Spending, addresses alignment of subsystem characteristics and utility strategic investments, asset attrition, capital expenditures, and operating expenditures. Chapters VIII, IX, and XI focus on AMI, DERs, and the baseline database, respectively.

IV. System Description and Configuration

A. Summary

The configuration of ComEd's distribution system has undergone a number of developments since 2012; this chapter describes them. Chapter V addresses the costs of capital and O&M programs, projects, and initiatives and Chapter VII describes system performance developments as these expenditures have accumulated. Distribution system performance measures provide the best means for examining holistically what benefits (or declines as the case may be) have accompanied the configuration changes addressed in this chapter and the system condition changes that in major part result from asset management and other O&M activities also addressed in Chapter VI. For purposes of this chapter, major sources of configuration change include those in the following list, which both exemplify the kinds of programs, projects, and initiatives commonly undertaken in the industry, and which, we believe, have all contributed to the system performance improvements detailed in Chapter VII.

- ComEd's distribution system remains primarily urban and suburban with the rural areas of its South and West Regions representing only nine percent of customers. The base electrical needs served by ComEd since 2012 have remained stable overall. Non-weather normalized peak load decreased by a substantial 14 percent (in a year impacted by COVID-19), as customer numbers increased by 6.4 percent. ComEd reports that load normalized for weather decreased by a lesser amount, 5 percent, from 2012 through 2019. Thus, new customer connections have required expenditures, while the addition of new substations and lines, a significant source of expenditure for utilities with faster growing loads has been moderate, although uneven growth in some areas has led to some expenditures for new resources to serve pockets of growth. Distributed Energy Resources (DER) interconnections have contributed a modest amount of energy (megawatts) to the grid. The peak megawatts (MW) of energy contributions to the electric grid by DER reached about two percent of the system load by year end 2020, as compared with the, at most, nominal MWs present in 2012.
- Continued investment in configuration-changing equipment and sectionalizations made ComEd's electric delivery system nearly fully redundant by 2020, allowing either automatic or manual transfer of customer loads. Of the Transmission Distribution Center (TDC) 114 substations that directly serve the distribution system from the transmission system, 109 have multiple transmission line sources and multiple substation buses (conductors connecting substation transformers to circuit breakers) allowing transfer of loads in case of the loss of an incoming line or substation transformer. Importantly, nearly all ComEd's distribution circuits have some level of redundancy. Customer loads on portions of 94 percent of ComEd's distribution circuits can be rerouted (by circuit tie devices) to nearby circuits upon the occurrence of a contingency threatening or producing service disruptions. The small remaining numbers of circuits lacking manual or automatic transferability either have very short lengths, serve low customer numbers, are remote, or have no other circuit in proximity.
- ComEd's distribution system configuration includes "secondary networks," used to serve customers in dense urban areas, which are made up of multiple supply sources and transformers that provide service when one or two primary voltage sources or transformers

are out of service. ComEd also employs automatic transfer switches (ATOs) for critical customers such as hospitals that transfer power between circuits in case of a circuit outage.

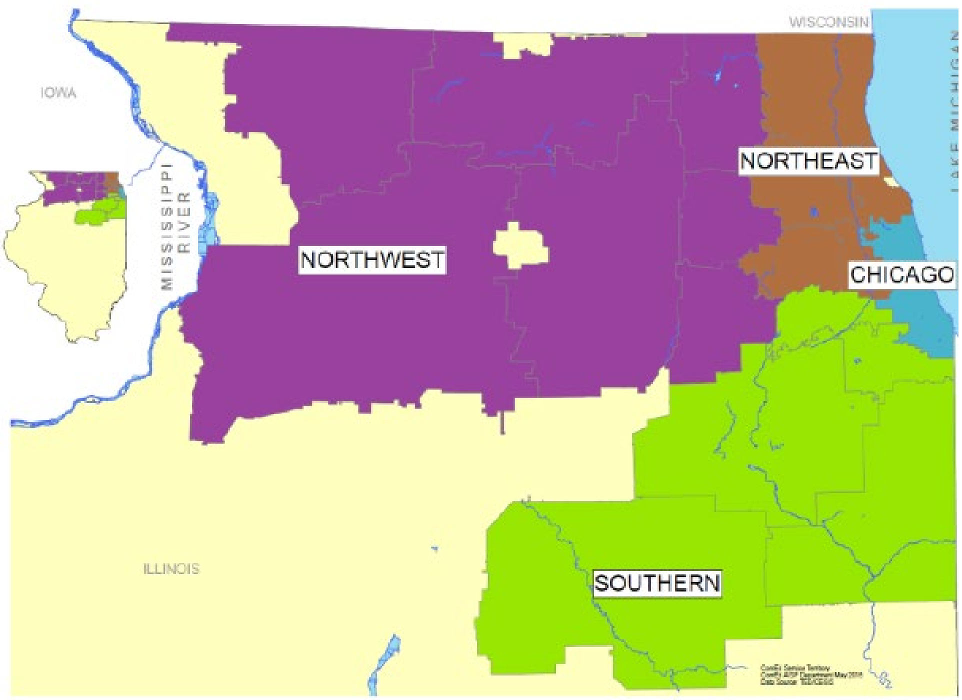
- ComEd completed full SCADA (Supervisory Control and Data Acquisition) system installations for substations by 2020, allowing system operators to monitor operating conditions and to control nearly 100 percent of substation equipment and circuit breakers remotely. ComEd has included and continues to include SCADA communications capability with many of its recently installed upgraded circuit reclosers (smart switches).
- ComEd's continuing modernization of protective relays has reached 40 percent of them, serving to reduce equipment damage, to locate circuit faults automatically, and to reduce customer outages.
- ComEd has continued to upgrade overcurrent protection of lateral circuits tapped off mainline circuits by replacing one-use-and-done fuses with automatic reclosing devices, a substantial effort, to enhance system configuration to improve reliability. ComEd reported that it had replaced "thousands" of lateral circuit fuses with reclosing devices, and it upgraded, and continues to upgrade, many of these reclosing devices with single-phase tripping to prevent customer interruptions on unaffected phases, and continues upgrading lateral circuit reclosing devices with communication schemes that prevent unnecessary protective device operations (by equipment sensors that identify fault locations and tell which protective device to trip).
- ComEd reported that, at most, the largest typical circuit outage results in 1,500 customer interruptions, but that it has a goal of eventually limiting the numbers of customers affected by a single circuit outage to less than 750. Its approach to reducing customer interruptions (CI) seeks to increase use of distribution automation (DA) devices and schemes. DA consists primarily of circuit sectionalizing devices, smart grids, and improved lateral tap circuit and substations protection devices and schemes. During the study period, DA work included increasing the numbers of automatic circuit reclosers by 143 percent and the numbers of "Smart Grid" schemes by 172 percent over 2012 levels. Management has captured the costs of these devices under its annual distribution system performance plant additions. Section C.5. of this chapter provides the numbers of reclosers and smart grid schemes installed during the study period.
- In 2020, ComEd's distribution system was slightly more than 50 percent overhead, but overhead wire circuit mileage slightly decreased during the study period, while underground cable circuit mileage increased slightly. Legacy underground cable problems have occurred throughout the industry. Continuing expenditures since 2012 resulted in replacement of much poor-performing underground cables. Management continues to replace poor performing underground cable to further reduce underground equipment caused customer interruptions.
- ComEd materially enhanced system capabilities, particularly focusing on reliability improvements and operability enhancement (which contributed to operating flexibility and economy, as well as enhancing reliability. The company, for example, made considerable expenditures to incorporate "smart" operating capability, line sensors, upgraded relays, and device communications. The substantial increase in numbers of distribution automation devices and "smart" operating capabilities during the study period has reduced the number of customers exposed to power outages.

B. Company Description

ComEd is owned by parent company Exelon Corporation, along with other Exelon-owned electric utilities in Pennsylvania, Maryland, Delaware, New Jersey, and Washington, D.C. Exelon Corporation provides standardized work practices and other common functions and services among its utilities.

ComEd operates as Illinois's largest electric utility, in terms of numbers of customers, serving over 4 million customers in 25 counties in northern Illinois, including over 400 municipalities within its 11,428 square miles territory. ComEd serves the urban Chicago area and the surrounding suburban areas, and some rural areas located northeast, northwest, and south of Chicago. The following map shows ComEd's four operating regions -- Chicago, Northeast, Southern, and Northwest Regions (also referred to in this report as Chicago, North, South, and West Regions).

ComEd Service Territory



ComEd's customers take electric service from about 506,552 overhead and underground distribution pole mounted, pad mounted, and underground service transformers. These service transformers connect to 5,629 distribution primary circuits, at 34kV, 12kV, and 4kV. The distribution system includes 66,730 miles of circuits, about 52 percent consists of overhead wires on poles, and about 48 percent underground cables. Urban-area customers comprise about 32 percent of those served by these, with 59 percent suburban, and 9 percent rural. ComEd's Chicago and North Regions have no rural customers. High customers per circuit mile densities prevail in the Chicago and North Regions with densities for rural circuits in the South and West Regions lower with averages of about 28 and 18 customers per circuit mile, respectively.

ComEd's total number of customers at the end of 2020 totaled 4,036,247, representing an increase of approximately 6.4 percent between 2012 and 2020. As indicated by the following table, between

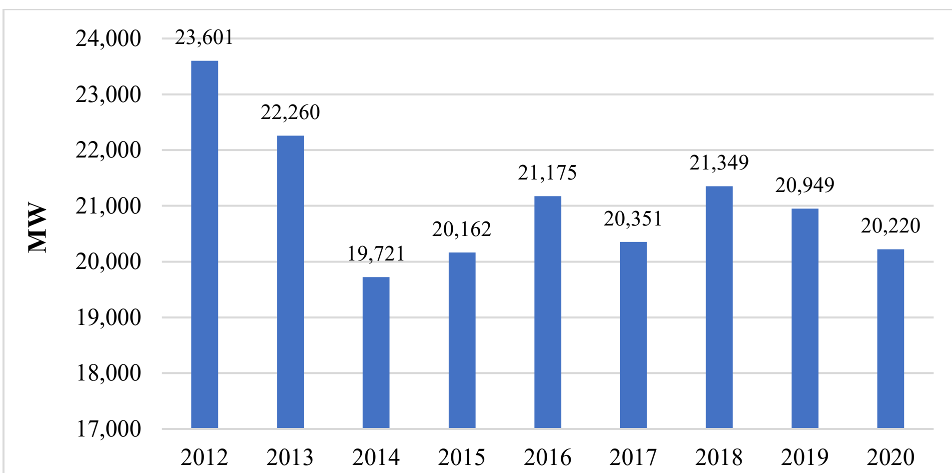
2012 and 2020 ComEd residential and commercial customer counts increased by six percent; its High Voltage customer counts (those served directly from the 69, 138, and 345kV systems) increased by 20 percent; but its industrial customer count decreased by 13 percent. ComEd also had 14 railroad customers and 8,788 lighting connections in 2020. At year-end 2020, ComEd had 2,317,359 single family customers and 1,325,938 multiple family customers.

ComEd Customer Counts

Customer Type	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	3,421,713	3,445,050	3,463,377	3,503,917	3,550,999	3,577,153	3,609,861	3,623,186	3,643,297
Commercial	362,468	364,450	364,676	366,831	370,941	374,422	378,907	381,845	384,015
Industrial	47	47	43	47	53	45	49	49	41
High Voltage	77	75	75	80	80	76	79	86	92
Railroad	14	14	14	14	14	14	14	14	14
Lighting	8,646	8,682	8,687	8,734	8,655	8,668	8,665	8,748	8,788
System	**3,792,965**	**3,818,318**	**3,836,872**	**3,879,623**	**3,930,742**	**3,960,378**	**3,997,575**	**4,013,928**	**4,036,247**

While ComEd's customer count increased by six percent between 2012 and 2020, its annual actual non-weather normalized peak load decreased approximately 14 percent during the same time period, with COVID-19, energy efficiency measures, and DER interconnections as contributing factors. DER interconnections provided about two percent of the distribution system load, with a maximum of 460MW at the end of 2020.

Peak Load



C. Distribution System Configuration

ComEd's distribution system configuration employs six principal elements:

- Transmission and High Voltage Distribution (HVD) that serves customers directly from 345kV, 138kV, and 69kV circuits
- Substation Types
- Overhead and Underground Distribution Circuits
- Low Voltage Service Transformers

- Distribution Automation – Automatic Circuit Reclosers and Smart Grid Schemes
- Automatic Lateral Tap Circuit Protection.

Each of these elements provides critical capabilities to the system. The current configuration of the system and the contribution of these elements to its operation present the principal opportunities for and obstacles to accommodating changing resource mixes, customer demands, and stakeholder objectives.

1. Transmission and High Voltage Distribution

ComEd's 345kV, 138kV, and 69kV electric transmission system circuits comprise the primary source of power to its distribution system. In 2020, ComEd operated two 345kV High Voltage Distribution circuits, 202 138kV circuits (two more 138kV circuits were added in 2021), and 28 69kV circuits. The transmission system includes about 5,800 circuit miles of circuits – ninety-three percent overhead and seven percent underground. The redundancy of the transmission circuits and substations provide alternate sources in the event an element of the transmission system fails or remains out for maintenance. The loss of a transmission transformer or supply circuit for multi-transformer high voltage substations may result in a momentary interruption until load automatic transfer to remaining lines or transformers.

ComEd distributes electric service directly to 92 high voltage industrial customers from its transmission system. ComEd refers to these customers as "high voltage distribution (HVD) customers." The next tables list the miles of overhead and underground high voltage directly serving customers by voltage.

High Voltage Distribution Circuit Miles (2020)

Overhead					
Voltage	**Total**	**Chicago**	**North**	**South**	**West**
345kV					0.4
138kV	690	24	118	274	274
69kV	53		15		38
Underground					
Voltage	**Total**	**Chicago**	**North**	**South**	**West**
138kV	85	72	5	7	2
69kV	72		71.5		0.5

2. Substation Types

ComEd substations include 284 Transmission Substations (TSS) and Transmission to Distribution Centers (TDC), 48 Switching Stations (SS), and 478 Distribution Centers (DCs). The TSS substations primarily convert transmission voltages, the TDC substations primarily convert transmission voltages to distribution voltages, and the SS and DC substations convert one distribution voltage to another. ComEd remotely monitors loads and alarms and controls the configurations of substation buses (buses are conductors connecting transformers to circuit breakers) and for the circuit breakers for all 810 substations via its Supervisory Control and Data Acquisition (SCADA) system. A large percentage of the TSS and TDC substations have modern, more effective, micro-processer relays for enhanced protection. Many of the TDC substations comprise modern modular substations with indoor distribution switchgear.

Of the 114 TDC substations that serve the distribution system, 109 have more than one transmission source. Unexpected or planned outages of one of the incoming lines or transformers produce automatic transfers of the incoming circuits and the low voltage buses to another source. The 478 DCs transfer energy among the 34kV, 12kV, and 4kV systems, like the SS substations, except that each DC only has one incoming line per transformer, precluding automatic switching to another source. However, when the 34kV source to a DC is lost, the 12kV and 4kV loads can be transferred by the circuit tie schemes. This table indicates the numbers of substations, by type, for the System and for each Region.

Numbers of Substations (2020)

Substations	Totals	Chicago	North	South	West
TSS	170	50	24	47	49
TDC	114	10	35	39	30
SS	48	26	5	10	7
DC	478	76	114	145	143

During the 2012-2020 study period, ComEd upgraded seven TSS and seven TDC substations with automatic substation bus transfer schemes using state of art communication among the relays. These upgrades reduce bus transfer speed and damage caused by bus faults while preventing paralleling of transformers which also can damage equipment due to high energy released when faults occur.

During the study period, ComEd upgraded legacy substation protective relays with modern microprocessor relays, as the next table summarizes. These relays are more reliable, require less maintenance, self-test, and provide more accuracy to identify faults and provide fault locations. Microprocessor relays, rather than legacy electromechanical relays, protect transformers, buses, and circuits at about half the 34kV and 12kV distribution substations.

Percentage of Microprocessor Relays by Voltage System (2020)

Voltage	System %	Chicago %	North %	South %	West %
765kV	68	0	0	71	60
345kV	74	77	59	83	73
138kV	39	42	29	42	44
69kV	27	28	0	0	24
34kV	47	38	40	55	55
12kV	42	32	43	65	53
4kV	13	5	25	16	32

3. *Overhead and Underground Distribution Circuits*

ComEd refers to its 5,629 34kV, 12kV, and 4kV circuits as “distribution circuits.” ComEd can manually, remotely, or automatically tie two different circuit sections together for about 94 percent of its distribution circuits, as the next table summarizes. The ability to tie circuit segments together reduces the number of customers affected by an outage.

Numbers of Distribution Circuits (2020)

Voltage	Total	Chicago	North	South	West
34kV Circuits	351	29	105	107	110
12kV Circuits	4,196	1513	1145	821	717
4kV Circuits	1,082	603	272	140	67
Total All Voltages	5,629	2,145	1,522	1,068	894
Number/% Circuits with Tie Capability	5,284/ 94%	1,909/ 89%	1,479/ 97%	1,025/ 96%	871/ 97%

The next table categorizes ComEd's total overhead distribution circuit mileage in 2020, which decreased by 118 circuit miles since 2012. ComEd's 4kV overhead circuit mileage also decreased, but its 12kV and 34kV overhead circuit mileage increased slightly. Distribution mainline circuits consist of the 34kV, 12kV, and 4kV overhead and underground lines running between substations and customers' service transformers that provide low voltage (480-volts or less) at customer meters. Some customer service transformers connect directly to the mainline of a circuit, while others connect to lines that are tapped off the mainlines, on so-called "lateral tap circuits." Lateral tap circuits comprise more than half of the 4kV and 12kV overhead circuit miles.

During the study period, ComEd's storm-hardening program resulted in the replacement of about 400 circuit miles of overhead line with underground cables, primarily to prevent tree-caused outages.

Overhead Distribution Circuit Miles (2020 vs. 2012)

Voltage	Total			2020		
	2012	2020	Difference	1 Phase	2 Phase	3 Phase
4kV	3,170	2,996	-174	1,493	303	1,200
12kV	28,543	28,547	+4	11,818	3,397	13,332
34kV	3,205	3,257	+52	0	0	3,257
Totals	34,918	34,800	-118	13,311	3,700	17,789

ComEd also operated underground cable circuits between substations and customer service transformers, some totally undergrounded circuits and other undergrounded sections of overhead circuit mainlines and laterals. Underground mainline circuits generally connect between substations and secondary networks and to Underground Residential Distribution (URD) networks.

The next table summarizes ComEd's total underground distribution circuit mileage in 2020. The 4kV underground circuit mileage remained unchanged, but ComEd's 12kV and 34kV underground circuit miles increased.

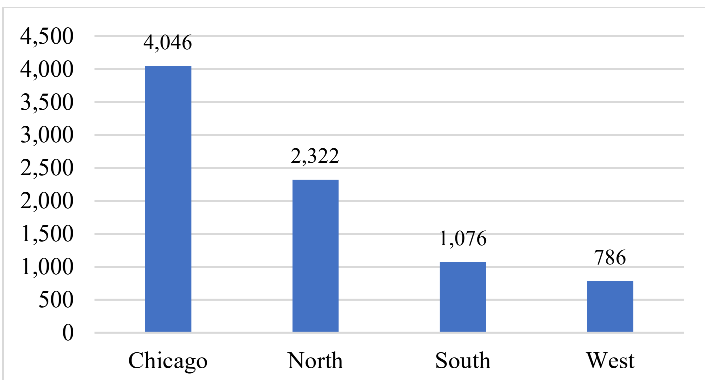
Underground Distribution Circuit Miles (2020 vs. 2012)

Voltage	Total			2020		
	2012	2020	Difference	1 Phase	2 Phase	3 Phase
4kV	1,683	1,681	-2	441	41	1,199
12kV	28,036	29,674	+1638	14,578	1,873	13,223
34kV	391	575	+184	132	0	443
Totals	30,110	31,930	+1,820	15,151	1,914	14,865

The prior two tables indicate that, since 2012, ComEd converted some 4kV overhead to 12kV and increased use of 12kV underground and 34kV underground and overhead distribution. ComEd typically converted 4kV circuits to 12kV circuits when aged 34kV/4kVsubstations became unreliable or parts were unavailable because of obsolescence.

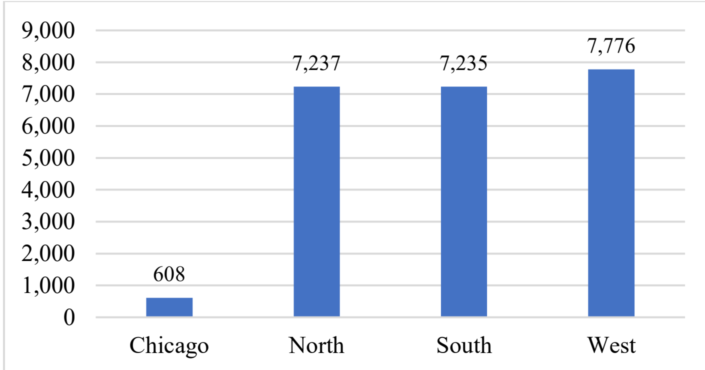
ComEd's underground systems included 8,230 miles of mainline circuits. The next chart shows the mileage of underground mainline distribution cables in each Region. Most of the mainline underground cable operated in the Chicago and North Regions.

Underground Mainline Cable Circuit Miles (2020)



The next table summarizes ComEd's 22,876 miles of underground residential distribution (URD) primary cable. The mileage of URD is small in the Chicago region but significantly larger, and about equal, in the other Regions. ComEd installed URD cables primarily in open loops with segments between numerous service transformers, and with a tie switch between the half loops. When a cable segment between service transformers fails, a first responder restores service by isolating the failed segment and closing the tie switch closing the loop to the de-energized segments.

Underground URD Circuit Miles 2020



ComEd employed underground "secondary voltage networks" to its downtown areas. These networks had multiple primary circuit sources to provide redundant reliability to its downtown areas typified by numerous customers in a small area. Large secondary networks operated in Chicago and Evanston, with smaller spot networks at malls, high rise buildings, and airports. These networks include about 1,950 network transformer and network protector sets. The mainline underground distribution system serves the network transformers for the secondary networks. Network transformers supply power to secondary (low voltage) network protectors (smart circuit breakers), which connect to secondary voltage networks, each serving many customers. The network protectors connect in parallel with other network protectors, and share a secondary network's load, even with one or more primary (4kV, 12kV, or 34kV) circuits or transformers are out of service. The network protectors provide transformer overcurrent protection, detect backfeed, and quickly open to prevent short circuit current back feed to a primary cable, without affecting the network's customers. These secondary networks provide at least N-1 redundancy, *i.e.*, the primary circuits and the transformers serving a network have sufficient numbers and capacity to allow one or more to be out of service without affecting customers.

4. *Low Voltage Service Transformers*

In 2020, ComEd operated 506,552 distribution service transformers to serve customers at secondary voltages (less than 600 volts) from the distribution circuits. Service transformers consisted of overhead pole-mounted, underground (URD pad-mounted, under sidewalks or in a vault), or dry-type pad mount transformers. The next table categorizes the large numbers (rounded except for network transformers) of service transformers on by region at the end of 2020.

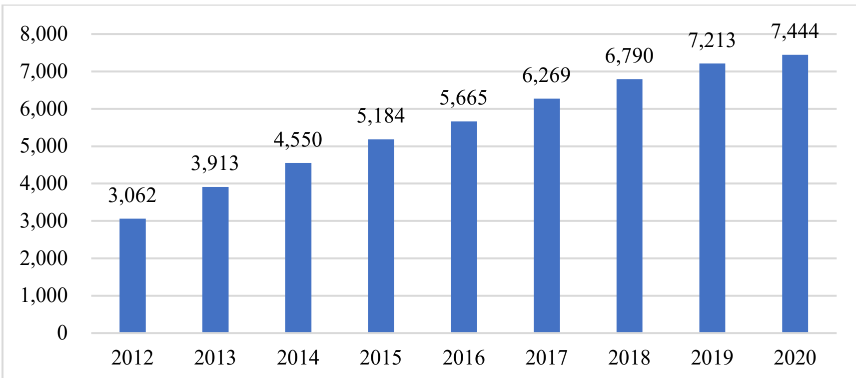
Distribution Service Transformers

Transformer	System	Chicago	North	South	West
Overhead	260,167	42,000	67,000	74,000	77,000
Underground	233,416	6,000	78,000	77,000	74,000
Dry Type	11,006	8,000	2,300	800	128
Network	1,963	1,732	197	8	13

5. Distribution Automation – Reclosers and Smart Grid Schemes

ComEd used automatic circuit reclosers, equipped with smart current and voltage sensing devices, as a primary means (among tap fusing, storm hardening and other improvements) to limit customer exposure to sustained outages and to provide reliability (as defined in Chapter VII: *Distribution System Performance*). As shown below, ComEd's 2012 through 2016 Energy Infrastructure Modernization Act (EIMA) program and continuing efforts under its baseline reliability programs increased the numbers of automatic circuit reclosers on distribution circuits, nearly all of which form part of smart grid schemes. Of the 7,444 reclosers installed by 2020, 5,300 operate under communication schemes that allow them to coordinate tripping with each other.

Accumulated Number of Reclosers

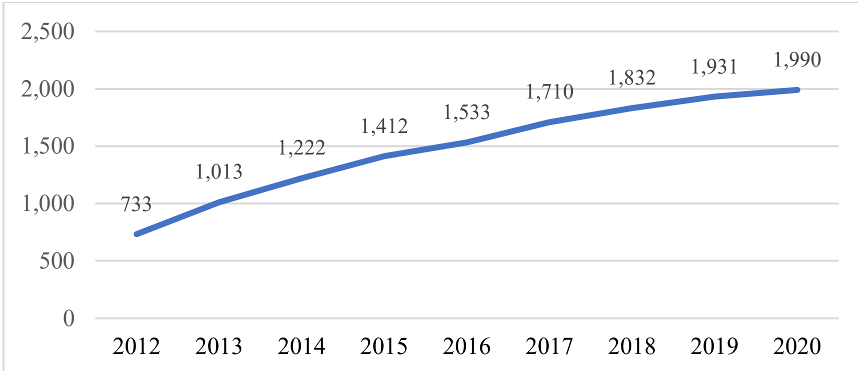


Under its Distribution Automation program, ComEd installed "Smart Grids" that employ reclosing devices (reclosers) that isolate a fault to one smaller segment of a circuit, limiting the numbers of customers affected by the fault, and they employ "smart circuit tie switches" (also reclosers) that automatically detect when a circuit segment becomes de-energized by a fault on an upstream segment. These smart tie switches use sensors and a smart algorithm to determine whether they can close to a second circuit, to automatically re-energize its segment, without overloading the second circuit. These "self-healing" schemes automatically minimize the customers experiencing a sustained interruption to those on a faulted segment and restoring service to the downstream segments. These schemes consist of mid-circuit reclosers and "smart switch" circuit tie reclosers, sensors, controllers, and communication systems. System operators monitor the sensors and reclosers and can control the reclosers, if required. Most of the circuits have multiple smart grid schemes (up to seven smart grids on some circuits).

Currently, smart grid schemes limit the number of customers interrupted by a typical circuit outage to less than 1,500 maximum. ComEd seeks eventually to install enough of these schemes to limit that maximum to between 400 and 750. Smart grid schemes generally produce lower benefit to cost ratios on short, low customer density, and remotely-located circuits where there are no opportunities to tie with other circuits. ComEd has therefore limited the use of smart grid schemes in such situations, but has employed them on some worst performing circuits and as part of targeted resiliency improvements.

By the end of 2020, ComEd had employed nearly 2,000 self-healing "smart grid" schemes. As shown below, between 2012 and 2020, ComEd employed 1,257 smart grid schemes on its distribution circuits for a total of 1,990 smart grid schemes by the end of 2020.

Accumulative Number of Smart Grid Schemes



6. Automatic Transfer Operators

ComEd has installed 1,465 automatic transfer (switches) operators (ATOs) at critical customer load points, such as at hospitals, which have two available sources. The ATOs consist of transfer switches that detect loss of voltage on the preferred source and automatically transfer load to the alternate source. The ATOs provide redundant capability for critical loads.

7. Automatic Lateral Tap Protection

Lateral tap circuits comprise "branches" connected to the mainline "trunk" circuit connected to a substation. These lateral tap circuits make up more than half of the overhead circuit mileage. Before the 2000s, many lateral taps directly connected to mainline circuits, causing faults on the lateral taps to produce in mainline circuit outages as well. An early 2000s reliability program employed a cost-reliability benefit analyses to identify locations for installing one-shot fuses between the taps and the mainlines. This program reduced mainline outages but required a first responder to replace fuses to restore service on the lateral taps. Around 2008, ComEd began replacing the fuses at the lateral taps with Trip Savers devices that could fit into fuse holders. Trip Savers automatically reclose the circuit to restore power following temporary lateral tap faults, *e.g.,* lightning strikes or light limb contact. Since then, ComEd installed thousands of these Trip Savers. However, these reclosing devices do not have the capability to communicate with other devices or with the system operators. ComEd has been systematically replacing Trip Savers with single or multiple phase reclosing devices that can communicate with other devices and with system operators.

V. Capital Investment and O&M Spending

A. Summary

We aligned ComEd capital plant addition amounts and O&M spending from 2012 through 2020 by major category. That alignment permits observations about trends in total spending and changes in emphasis between capital and O&M and among specific categories within those categories. These categories and the changes in them have importance for planning, particularly in showing the large amounts that have been spent and that will continue to be required simply to maintain system condition through replacements and to meet the obligation to serve new loads. This approach also supports an examination of how changes in annual spending by category conform to the increasing ubiquity of certain system features, providing an indication of what it may take to ratchet spending up or down in those categories with lower penetration rates, depending on the goals, targets, and values that will drive future planning.

This category-based approach does not underemphasize individual projects that have alone consumed large expenditures. Rather, it highlights sources of expenditure that may not produce individual projects of large dollar magnitude but which nevertheless, through repetition across the system year-by-year, generate enough work to consume large collective dollar amounts and to produce material benefits in system configuration, condition, and performance. The database that accompanies this report, which we consider to potentially have sustaining value if updated regularly, has particular importance here. There are too many projects and changes in expenditures over time to attempt to capture them all in narrative form. The database allows stakeholders to sort and analyze data in multiples ways for use in planning. Additionally, the database permits a project-by-project focus on larger projects individually and allows for sorting by expenditure type and changes in configuration (*e.g.*, penetration rates of certain automated control equipment). The database will permit stakeholders to develop data sorts and perform analysis of both large scale and very particular elements of the system that system planning will address.

The observations presented below fall among those that traditionally form focus areas in planning system capital and O&M expenditures. We emphasize, however, that the purpose of our study is not to tell readers what we think are the most important things to consider, but rather to provide data in a form that will permit planning stakeholders to form their own observations and develop their own positions. With that caution, the following present some of our major observations from analysis of the data provided.

- ComEd added to its distribution capital plant during the 2012 through 2020 study period as follows:
  - $10.7 billion of plant additions under Distribution Capital Plant categories. $2.5 billion came under the EIMA Infrastructure Investment Plan (IIP). See Section C.8, *EIMA Infrastructure Investment Plan*, for reliability-related investments for descriptions of the programs included in the IIP.
  - $2.0 billion was allotted to ICC jurisdictional distribution general and intangible category. Section B.1 of this chapter describes the Distribution General and Intangible plant category.
  - Overall, expenditures increased ComEd's total annual distribution capital plant additions by more than 95 percent between 2012 and 2020. The peak year for capital

additions occurred in 2016, associated with EIMA-related projects. Annual general and intangible plant additions increased by about 41 percent during the period.

- ComEd managed its capital plant program work using "capital blankets" to maximize management control of projects. To examine smaller cost grouping within the various plant addition categories see Section B.7, *Capital Program Blankets* for descriptions and investments for projects within those capital blankets.
- Plant additions for capacity expansion, new business connections, and legally required relocation of facilities, while requiring cost-benefit analyzes and formal authorizations, are generally obligatory. However, capital plant additions and O&M spending for distribution circuits and substation maintenance and for system performance had some flexibility, primarily based on retaining equipment conditions and attaining various reliability targets.
- 2020 System Performance plant additions proved 120 percent greater than those of 2012, with this category (which included capital costs of ComEd's EIMA and non-IEMA reliability programs) producing the largest gain in distribution capital plant during the study period.
- With the primary purpose of improving system reliability, ComEd invested nearly $3.7 billion for system performance plant, including about $2.7 billion for the distribution system, $218 million for relay and protection, $615 million for substations, and $130 million for the high voltage distribution system.
- ComEd increased its annual system performance capital plant additions from $214 million in 2012 to $635 million in 2016, the peak of the EIMA programs, then it reduced annual plant additions to $346 million in 2019, increasing to $470 million in 2020.
- 2020 Corrective Maintenance plant additions exceeded those in 2012 by 48 percent, making it the second greatest contributor to ComEd's distribution capital plant during the study period (this category included capital costs of distribution circuit and substation equipment and component replacements).
- ComEd invested $2.9 billion in Corrective Maintenance distribution capital plant with the primary purposes of improving reliability by maintaining the conditions of ageing distribution circuits and substation and reducing equipment malfunctions.
- ComEd steadily increased its annual Corrective Maintenance plant additions from $276 million in 2012 to $357 million in 2019, increasing to $408 million in 2020, primarily the result of the August 2020 derecho.
- This Corrective Maintenance plant category included distribution capital plant required for storm restoration, with such restoration producing plant additions between $19 million in 2016 and almost $69 million in 2020 - - this last year affected by the August derecho.
- Total O&M spend during the study period was about $4.2 billion, with annual amounts growing by 38 percent, from $410 million in 2012 to $564 million in 2020.
- Corrective Maintenance, vegetation management, and Information Technology (for IT services provided for the Energy Management System (EMS), the Voltage Optimization program, and the Advanced Metering Infrastructure (AMI) projects accounted for the largest shares of 2020 O&M spending.
- Corrective Maintenance (CM) proved the largest single source of O&M spending, covering labor for inspections, repairs, and equipment and component replacements.

- Annual distribution system and substation maintenance O&M spending increased about 16 percent during the study period, with about $2.2 billion O&M for corrective and preventive maintenance, including $581 million for storm restorations (with $132 million in 2020 in a year with a system wide derecho weather event in August).
- Annual Corrective Maintenance O&M spending decreased from $229 million in 2012 to $195 million in 2019, then increased to $265 million in 2020.
- Storm O&M decreased from $71 million in 2012 to $39 million in 2016, increasing to $62 million in 2019 and to $132 million in 2020.
- O&M spend for Vegetation Management totaled $737 million during the study period.
- Annual O&M spending for Vegetation Management increased by about 73 percent, from $60 million in 2012 to $104 million in 2020, primarily due to the enhanced tree trimming and tree removal programs implemented during the study period.
- Customer reliability measures improved substantially during the study period, as ComEd made substantial capital expenditures on Reliability Improvements and made significant O&M expenditures focused on reliability as well.
- SAIFI and CAIDI metrics excluding extreme weather events bettered EIMA targets each year.
- 2020 EIMA SAIFI performance improved by about 50 percent as compared with the baseline EIMA period (2001-2010).
- 2020 EIMA CAIDI performance improved by about 24 percent as compared to the baseline EIMA period.
- Based on IEEE with major event days (MED), measures with storms included have also improved generally, with system SAIFI improved by a third by 2020, and system CAIDI improving by 46 percent by 2019.
- However, CAIDI performance with storms included worsened substantially in in 2020, influenced by the August derecho event.
- Capital and O&M spending on corrective maintenance, vegetation management, and distribution automation and other EIMA and non-EIMA programs (particularly smart grids) contributed to reduced numbers of equipment caused customer interruptions (CI) and customer minutes of interruption (CMI) and tree caused CI.
- Overhead equipment caused CI and CMI both fell, by 27 percent and 45 percent, respectively. Underground equipment caused CI and CMI fell by 55 percent and 61 percent, respectively, while tree caused CI fell by 37 percent but CMI increased by 43 percent.
- Applications of distribution automation (Smart Grids and other advanced sectionalizing and protection devices), augmented by reliability programs during the study period, contributed to annual reductions of CI and CMI.
- Installing distribution automation (DA) devices and schemes provide reliability improvements while avoiding the need for large recurring expenditures that maintenance methods (*e.g.,* equipment inspection and repair maintenance and vegetation management), impose, making judicious installation an important contributor to reliability.

B. Total Capital Plant Additions and O&M Expenditures

1. Capital Plant Additions - 2012 through 2020

Under its capital "Distribution Plant Additions" category, ComEd annually reports plant addition subcategories that were tangibly added to the distribution system under various subcategories. ComEd also annually reports the ICC Jurisdictional portion of its "General and Intangible" capital additions. The ICC-reported values exclude expenditures whose costs are not recoverable under rates that the ICC establishes (*e.g.*, transmission expenditures subject to FERC-determined cost recovery). The following table shows the major subcategories (those over $10 million) where ComEd added capital plant during the study period.

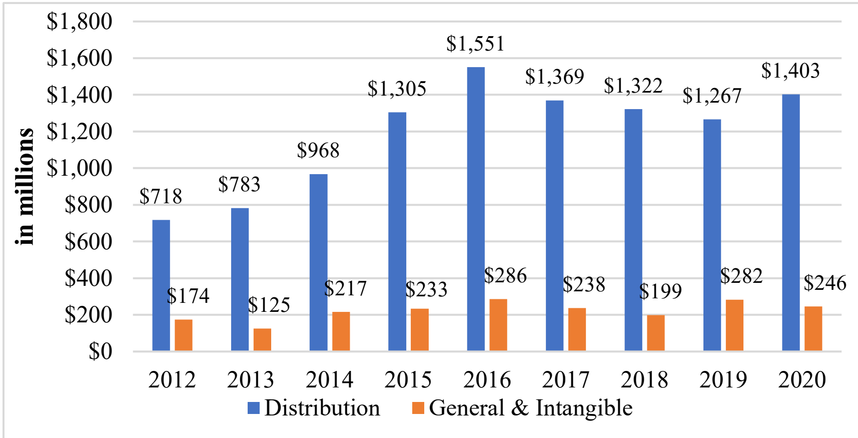
Capital Plant Additions by Major Category

Category	Additions in Millions		
	2012	2020	Total: 2012 through 2020
Distribution Plant Additions			
Capacity Expansion	$44.5	$180.9	$975.3
Corrective Maintenance	$275.8	$408.2	$2,897.2
Customer Operations	$13.9	$15.3	$802.0
Public (Facilities) Relocation	$57.2	$48.6	$424.8
New Business	$111.8	$282.6	$1,795.5
System Performance	$214.4	$470.0	$3,783.6
General and Intangible Plant Additions			
System Performance/Other	$0.0	$58.5	$198.1
Tools	$6.3	$11.8	$75.9
Vehicles	$45.4	$28.4	$310.1
Real Estate	$30.6	$29.0	$443.7
Customer Operations - Intangible Plant	$0.0	$21.5	$172.5
IT Projects - General Plant	$48.5	$31.9	$214.1
IT Projects - Intangible Plant	$39.7	$60.1	$426.2

ComEd added $10.7 billion in distribution plant and about $2.0 billion for ICC jurisdictional general and intangible plant during the period. The total amount includes EIMA capital spending of $2.5 billion, less than 25 percent of total distribution plant additions. ComEd's total annual distribution capital plant additions increased by more than 95 percent between 2012 and 2020. The peak year for capital additions occurred in 2016, driven significantly by EIMA-related projects. Annual general and intangible plant additions increased by more than 41 percent during that period.

ICC jurisdictional General and Intangible plant additions included items such as IT projects for the Energy Management (EMS) System, Voltage Optimization Implementation, and AMI. The General and Intangible plant category accounted for about $2.0 billion of plant additions between 2012 and 2020. The following chart shows total annual Distribution plant additions and General and Intangible plant additions over the period.

Annual Plant Additions

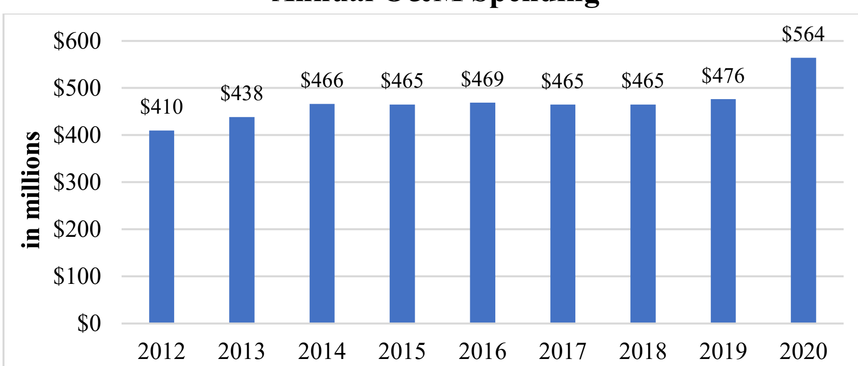


Spending for annual general and intangible plant additions comprised about 15 percent of total distribution plant additions. IT Projects investments during the 2012-2020 period proved substantial, representing $640 million in capital plant additions.

2. *O&M Spending – 2012 to 2020*

ComEd Distribution O&M spending totaled about $4.2 billion during the study period. ComEd's annual ICC jurisdictional distribution system O&M spending increased between 2012 and 2014, remained level between 2014 and 2019, and increased by about 18 percent from 2019 to 2020.

Annual O&M Spending



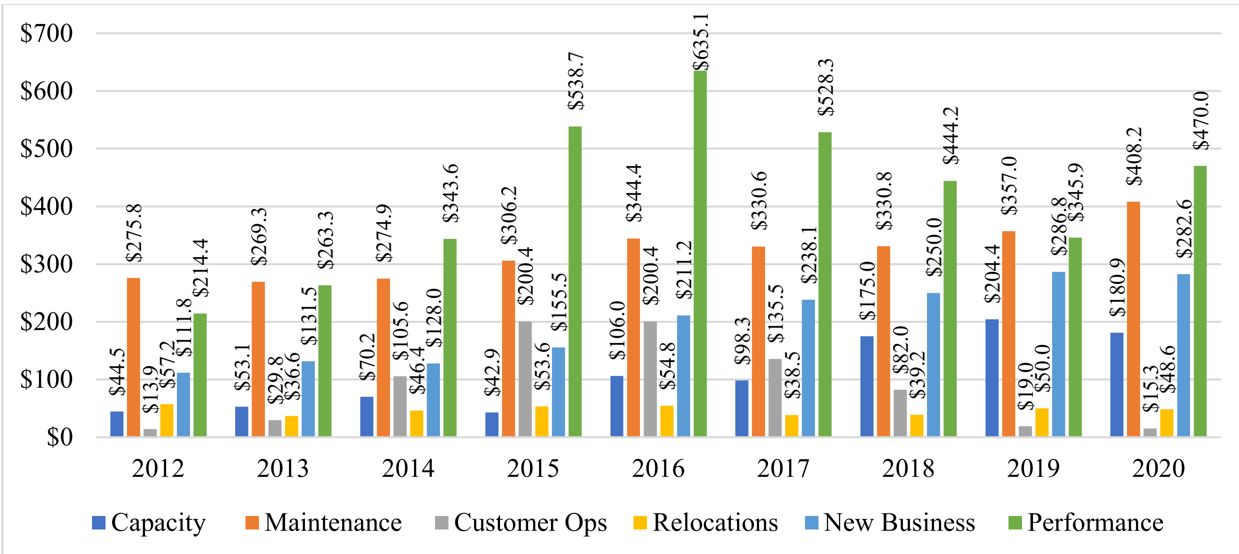
ComEd's O&M annual spending increased by $154.3 million from about $410 million in 2012 to about $564 million in 2020, a 38 percent rise, with the largest increases associated with vegetation management, corrective maintenance, and IT projects.

C. Capital Additions

1. *Distribution Plant Additions Overview*

The following chart breaks annual plant additions into six distinct categories included in Distribution plant from 2012 and 2020: Capacity Expansion (including voltage optimization), Corrective Maintenance, Customer Operations, Facilities Relocations, New Business, and System Performance. Notably, System Performance work represented the largest amount of distribution plant additions, followed by Corrective Maintenance.

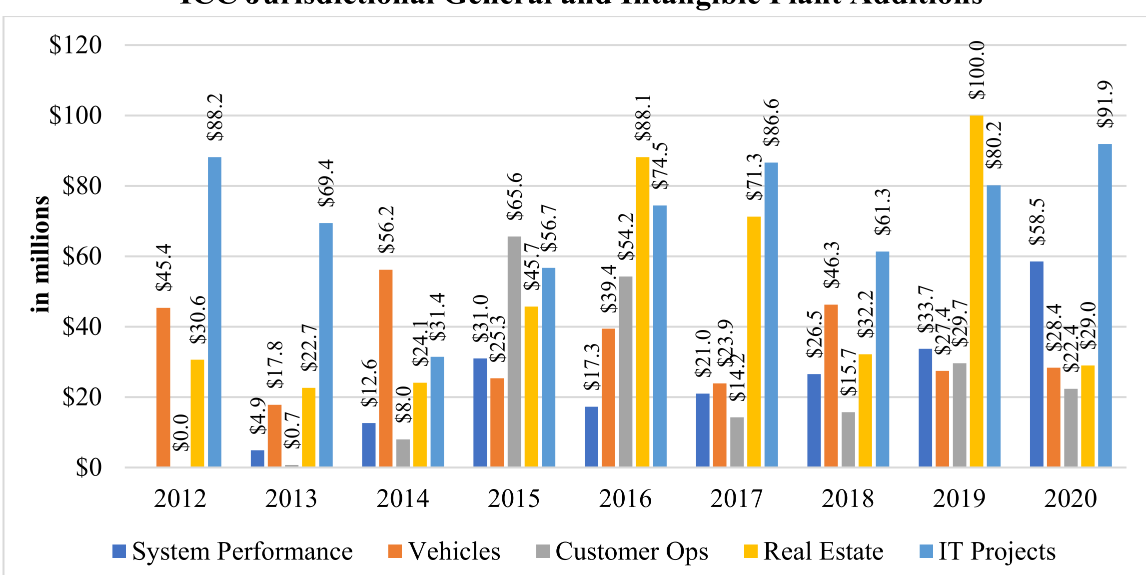
Distribution Plant Additions



2. General and Intangible Plant Additions

The next chart aligns plant additions by major categories included in General and Intangibles plant: System Performance, Vehicles, Customer Operations, Real Estate. General and Intangible Plant categories also appear in Distribution Plant categories. IT projects dominated general and intangible plant capital additions for most years, followed by vehicles and real estate.

ICC Jurisdictional General and Intangible Plant Additions

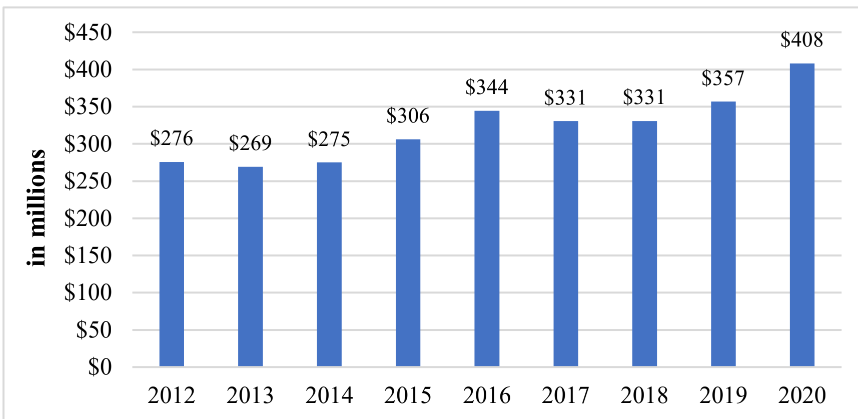


3. *Corrective Maintenance*

Corrective Maintenance capital plant additions and O&M drive distribution system configuration and condition and assist in preventing equipment caused outages. Corrective Maintenance replaces and updates aged, deteriorated, or obsolete distribution circuit and substation equipment and components, such as poles and substation transformers. Such maintenance controls equipment-caused outages. *(See Chapter VI, Distribution System Condition, for descriptions of ComEd's inspection and maintenance programs).*

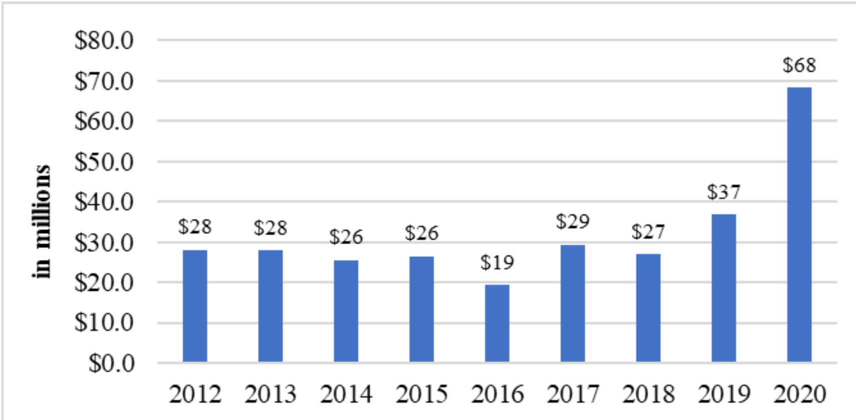
As system equipment has continued to age, ComEd's annual capital investments for corrective maintenance have increased. Between 2012 and 2020, of the $10.7 billion of total capital distribution plant additions, ComEd invested almost $2.9 billion for corrective maintenance plant. Expenditures have included over $2.6 billion for distribution corrective maintenance, $237 million for substation corrective maintenance, and $31 million for HV corrective maintenance. The chart below shows that annual corrective maintenance related plant additions increased markedly between 2012 and 2020, with plant additions in 2020 nearly 50 percent greater than those of 2012.

Distribution CM Plant Additions



Distribution capital additions from storm restoration costs were included in the Corrective Maintenance plant category. Storm restoration capital plant additions were level during the study period until decreasing in 2019 and then increasingly substantially in 2020 due to the August 2020 derecho. See Section D for O&M spending for storm restorations.

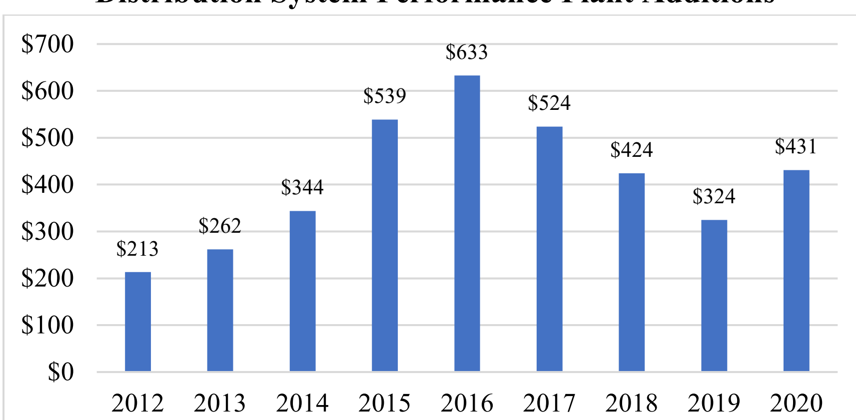
Storm Capital Plant Additions in the CM Category



4. *System Performance*

ComEd's baseline (*i.e.,* non-EIMA) and EIMA system performance (reliability and resiliency) programs targeted meeting or exceeding EIMA required reliability metrics. Funding directly affected (*e.g.,* cable replacements and distribution automation) and indirectly affected (*e.g.,* EIMA program training facilities) distribution system reliability. Between 2012 and 2020, out of the $10.7 billion total capital plant additions, ComEd invested almost $3.7 billion in system performance plant. This amount included about $2.7 billion for the distribution system, $218 million for relay and protection, $615 million for substations, and $130 million for the high voltage distribution system. Not including the Smart Meter capital plant additions (See Chapter VIII, *Advanced Metering Infrastructure*), these funds included about $1.6 billion for ComEd's EIMA Infrastructure Investment Plan (IIP). The chart below shows that ComEd's capital plant for system performance peaked in 2016 due in large part to EIMA funded system performance work. (See Chapter VII for descriptions of ComEd's Distribution System Performance programs).

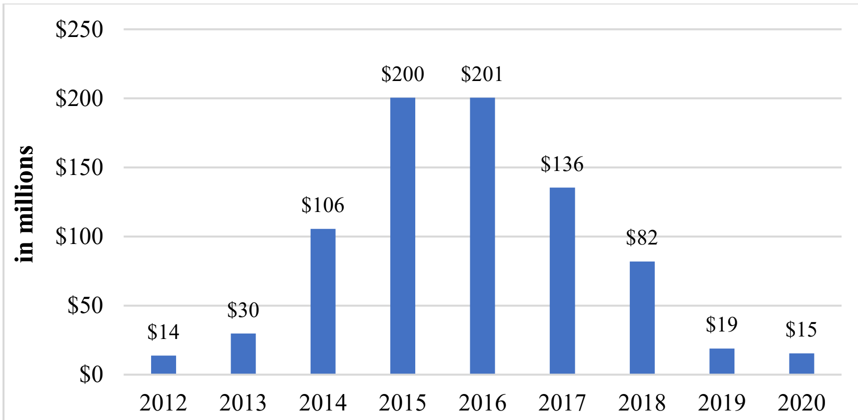
Distribution System Performance Plant Additions



5. *Customer Operations Plant Additions*

ComEd increased its total Customer Service and Field Operations distribution capital plant by $802 million during the study period, primarily due to implementation of Advanced Metering Infrastructure (AMI). AMI costs were also included in other plant subcategories, such as information technologies (IT). The following chart depicts customer operations annual plant additions each year.

Customer Operations & Field Operations Plant Additions



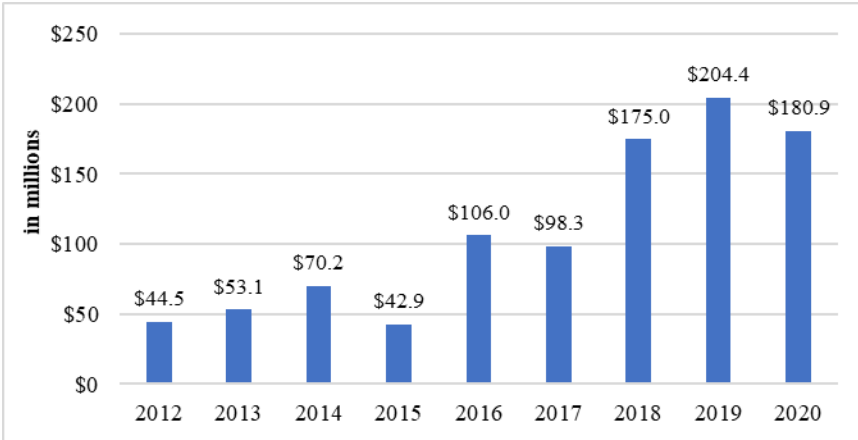
6. *Capacity Expansion, New Business, and Facilities Relocation*

These capital addition categories do not directly target reliability improvement, but they did significantly increase the amount of distribution capital plant added to the system. These capital categories required funding to comply with system operations criteria and regulatory requirements, thereby providing additional infrastructure, and increasing capital distribution plant value. Between 2012 and 2020, out of the $10.7 billion ComEd invested in all distribution plant categories, Capacity Expansion (including voltage optimization) received more than $975 million, New Business received $1.8 billion, and Facilities Relocation (required to fund the relocation of its infrastructure when requested by city, county, and state highway agencies) received $425 million in funding.

a. Capacity Expansion

Although ComEd’s system peak loads have decreased since 2012, peaks have grown in specific planning areas, requiring additional distribution plant. Between 2012 and 2020, out of the $10.7 billion of total capital plant additions, ComEd invested more than $975 million for capacity expansion, including about $931 million for distribution expansion with voltage optimization included, and $38 million for high voltage distribution expansion. This funding ensured that the distribution system operated within the planning criteria, thereby avoiding increasing peak circuit or substation load criteria violations. ComEd’s 2020 annual capital investment for capacity expansion increased by about 300 percent from 2012 levels, including about $200 million for voltage optimization from 2017 through 2020. The following chart depicts the annual capacity plant additions each year.

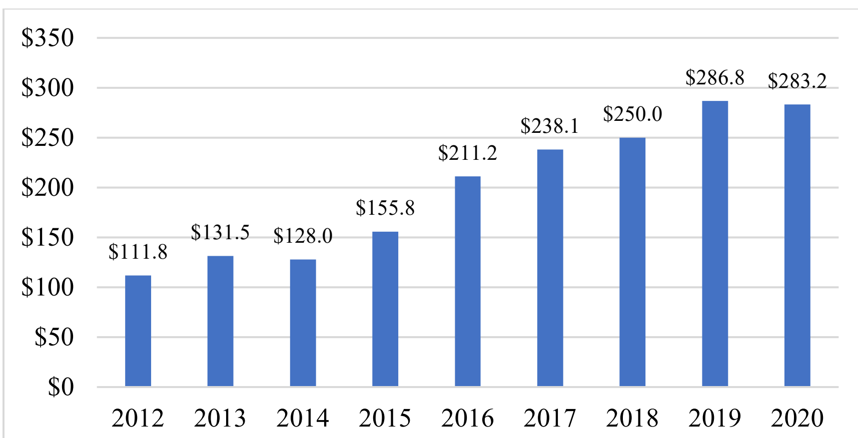
Distribution Capacity Expansion Plant Additions



b. New Business

Between 2012 and 2020, of the $10.7 billion of total capital plant additions, ComEd invested about $1.8 billion for new business plant to meet customer connection needs. ComEd's 2020 annual capital investments for new business increased about 150 percent compared to 2012, as shown below.

New Business Plant Additions



c. Facilities Relocation Capital Category

ComEd is required by regulation to fund the relocation of its facilities if requested by certain governmental agencies. During the years 2012 through 2020, ComEd invested about $425 million for facilities relocation, ranging between $37 million to $57 million annually; plant additions in 2020 totaled about $49 million.

7. Capital Program Blankets – 2016 through 2020

Although all projects over $100,000 must go through a multi-phase authorization process, ComEd generally funds discrete, repetitive day-to-day tasks less than $100,000 from "capital blankets" or "bucket" accounts, each managed by one Category Manager, thereby streamlining funding approval and acquisition. ComEd generally invests in 15 blanket programs, or programs not necessarily associated with specific projects, to accomplish work in each of six major capital investment categories - Corrective Maintenance, Capacity Expansion, New Business, Facilities Relocation, System Performance, and Customer Operations. The next table summarizes the major blankets ComEd had in place between 2016 and 2020.

Capital Program Blanket Summary

<table>
<tr><th>Capital Blanket</th><th>Description</th><th>Funding</th></tr>
<tr><td>Capacity Expansion</td><td>ComEd charges its small routine capacity expansion projects to one investment tracking number (ITN), which includes projects that each did not exceed $100,000.</td><td>$3.3 million in 2018, $4.6 million in 2019, and $3.2 million in 2020.</td></tr>
<tr><td>New Business Installations</td><td>Provides baseline funding for new residential and commercial services. These services include both the overhead and underground services outside Chicago and new overhead services in Chicago.</td><td>$118.7 million in 2016, $119.8 million in 2017, $128.3 million in 2018, and $151.3 million in 2019, and $148 million in 2020.</td></tr>
<tr><td>Facilities Relocations</td><td>Funds baseline distribution infrastructure relocation projects, such as when a governmental entity (municipality, county, or state agency) decides to undertake a public project, that do not exceed $100,000.</td><td>$5.4 million in 2019 and $6.1 million in 2020 for small facilities relocation projects.</td></tr>
<tr><td>Underground Corrective Maintenance</td><td>Funds of day-to-day emergency corrective actions for underground cable and equipment failures. During 2016 through 2018 this blanket included emergency underground equipment and cable fault repairs throughout the ComEd system. In 2019, this program also included post EIMA Manhole Replacement and Underground Programmatic Corrective Maintenance.</td><td>UG Corrective Maintenance<table><tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr><tr><td>$M</td><td>65.2</td><td>65.4</td><td>52.5</td><td>58.1</td><td>58.9</td></tr></table></td></tr>
<tr><td>Overhead Corrective Maintenance</td><td>Includes numerous ITN accounts to fund discrete tasks, such as replacing poles, overhead transformers, wire, fuses, connectors, brackets, braces, and arresters. It is a large blanket that includes storm restoration costs, and substation corrective maintenance, emergency transformer repair and replacement, non-emergency corrective maintenance, emergency pole replacement, overhead repairs, reject pole replacement costs, and other repair costs.</td><td>Overhead Corrective Maintenance<table><tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr><tr><td>$M</td><td>136.9</td><td>178.2</td><td>212.3</td><td>235.0</td><td>219.4</td></tr></table></td></tr>
<tr><td>Distribution Transformer Repair and Replacement</td><td>Funds transformer repairs and replacements required to replace failed or obsolete transformers, and for new installations required to maintain service to ComEd customers.</td><td>Distr. Transformer Repair and Replacement<table><tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr><tr><td>$M</td><td>47.8</td><td>48.0</td><td>45.2</td><td>42.2</td><td>40.6</td></tr></table></td></tr>
<tr><td>System Reliability Programs</td><td>Includes accounts for system reliability work focusing on reducing the frequency, and to a lesser extent, the duration of customer interruptions; includes accounts for installing distribution automation reclosers, replacing</td><td>System Reliability Program<table><tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr><tr><td>$M</td><td>5.5</td><td>122.4</td><td>173.0</td><td>143.4</td><td>198.9</td></tr></table></td></tr>
</table>

<table>
<tr><td></td><td>URD and mainline cables, customer targeting programs, mitigating CEMI outages, wood pole replacements, and circuit reliability programs.</td><td></td></tr>
<tr><td>Grid Resiliency Programs</td><td>Funds program work designed to focus on customers experiencing multiple and extended duration interruptions, as well as the airport, system, and overhead and underground grid resiliency and durability programs, and the 34kV upgrade program.</td><td>Grid Resiliency
<table>
<tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>$M</td><td>18.6</td><td>28.9</td><td>3.0</td><td>1.5</td><td>0.3</td></tr>
</table></td></tr>
<tr><td>System Protection and Control Programs</td><td>Involves the conversion from leased line analog SCADA circuits to fiber optic and microwave systems due to carriers discontinuing support of these circuits over the next 3 to 5 years. It also includes investments to enhance the security and reliability of the Bulk Electric System and ensure compliance with the standards set by NERC.</td><td>System Protection and Control
<table>
<tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>$ M</td><td>27.3</td><td>3.2</td><td>2.5</td><td>4.1</td><td>0.3</td></tr>
</table></td></tr>
<tr><td>Voltage Optimization Program</td><td>Voltage Optimization (VO) is an energy conservation program, but it has aspects related to system reliability and capacity. Voltage Optimization is the automatic process, by a central computer, of maintaining feeder voltages at the most conservative, but acceptable, levels and minimizing reactive current flow. The benefits of this program are to reduce energy losses, to reduce system loads and peak demands, and to reduce customer energy consumption (because of slightly lower average voltages).</td><td>Voltage Optimization Program
<table>
<tr><td>Year</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>$ M</td><td>9.6</td><td>51.2</td><td>66.7</td><td>72.0</td></tr>
</table></td></tr>
<tr><td>Renewable Energy Advanced Control and Telemetry</td><td>Some DER interconnections require that ComEd have the ability to monitor and control devices on the circuit with the DER interconnection. This blanket includes the costs the install equipment, such as fiber optic cable, to provide additional communications and telemetry capabilities in several locations on the distribution grid, and to continue moving away from obsolete 3G wireless and copper wire technologies.</td><td>$2.8 million in 2019 and $31.2 million in 2020</td></tr>
<tr><td>Distribution System Modernization Program</td><td>Includes work to improve reliability, safety, and operability of the distribution system by replacing outdated equipment and reconfiguring existing equipment.</td><td>Distribution System Modernization Program
<table>
<tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>$ M</td><td>21.4</td><td>21.7</td><td>35.9</td><td>25.5</td><td>29.2</td></tr>
</table></td></tr>
<tr><td>Spare Large (>10MVA) Substation Transformers</td><td>Designed to procure, strategically store, and maintain distribution size spare transformers (classified as >10MVA to 75MVA) that can be placed into service in and expeditious manner as necessary to support ComEd system reliability.</td><td>Spare Large Transformer Program
<table>
<tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>$ M</td><td>23.8</td><td>17.2</td><td>32.3</td><td>3.4</td><td>4.5</td></tr>
</table></td></tr>
</table>

<table>
<tr><td>Underground and Overhead Hardening Blankets</td><td>Designed to improve the resiliency of the distribution system by targeting chronic reliability issues and reduce the numbers of customers experiencing multiple interruptions and extended interruptions.</td><td>These two blankets included accounts for Underground Hardening with a spend of $2.5 million in 2016 only, and for Overhead Resiliency for a spend of $7.5 million in 2016 only.</td></tr>
<tr><td>Customer Field Operations Capital Blanket (not Smart Meters)</td><td>This blanket accounts for the purchase of meters for the purpose of exchanges, new business installations, and to fulfill regulatory requirements (periodic exchanges).</td><td>Customer Field Operations<table><tr><td>Year</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr><tr><td>$ M</td><td>12.3</td><td>10.9</td><td>12.1</td><td>6.4</td><td>15.5</td></tr></table></td></tr>
</table>

8. *EIMA Infrastructure Investment Plan Reliability-Related Investments*

The EIMA IIP programs fell into two groups, the Reliability Investment Programs, which totaled $1.26 billion, and the Smart Grid Program, which totaled about $1.28 billion. The total funded amounted to $2.54 billion. The following table shows the dates, capital funding, and reported benefits of the IIP Reliability Investment Programs. Except for the new training centers, reliability-related funding was intended to reduce the numbers of power outages, customer interruptions (CI) and customer minutes of interruption (CMI). See Chapter VII: *Distribution System Performance*, for IIP program details.

IIP Reliability Investments

IIP Reliability Investment Program	Years of Activities	Capital Funding	Benefit
URD Cable Injection and Replacement	2012 through 2017	$545 million	URD cable caused outages reduced from 6,424 in 2012 to 2,799 in 2020
Mainline Cable Replacement	2012 through 2017	$392 million	Mainline cable caused outages reduced from 694 in 2012 to 381 in 2020
Ridgeland 69kV Cable Replacement	2012 through 2015	$31 million	Reduced 69kV sub-transmission outages to improve SAIFI and CAIDI
Construction of Training Facilities	2012 through 2015	$10 million	Ensures that skilled field workers continue to provide expert and efficient work practices
Wood Pole Inspection, Treatment, and Replacement	2011 through 2016	$81 million	Ensured that wood poles were sufficiently strong to provide safety and to resist the forces of storms
Storm Hardening	2011 through 2017	$202 million	Weather-related outages reduced from 6,036 outages in 2012 to 5,426 in 2020

9. *IIP Smart Grid Investment Programs*

ComEd intended its IIP Smart Grid Investment Programs to reduce the numbers of customers effected by outages. The following table summarizes these programs, and Chapter VII: *Distribution System Performance*, describes them in more detail.

IIP Smart Grid Investment Programs Summary

IIP Smart Grid Investment Program	Category	Years of Activities	Capital Spending	Benefit
Distribution Automation	System Performance	2012 through 2016	$242 million	Over 15 million ACI contributing to EIMA SAIFI reduction from 0.847 in 2012 to 0.498 in 2020
Substation micro-processor relay upgrades	System Performance	2012 through 2020	$134 million	Modernized 14 substations to provide best system protection and communication
Smart Meters (AMI)	Customer Operations/System Performance	2012 – 2019	$905 million	See Chapter VIII: *Advanced Metering Infrastructure*
Associated Cyber-Secure Data Communication Network	Customer Operations	Included with smart meter	Included with smart meter	See Chapter VIII: *Advanced Metering Infrastructure*

10. Distribution Capital Accounts Greater than $2 Million

ComEd had almost 500 capital plant accounts (*i.e.,* ITNs – Investment Tracking Numbers) of over $2 million and up to $700 million, during the study period. The data indicates opening and closeout dates (in some cases), funds allotted, description, the reasons for the program or project, and alternative solution(s) considered.

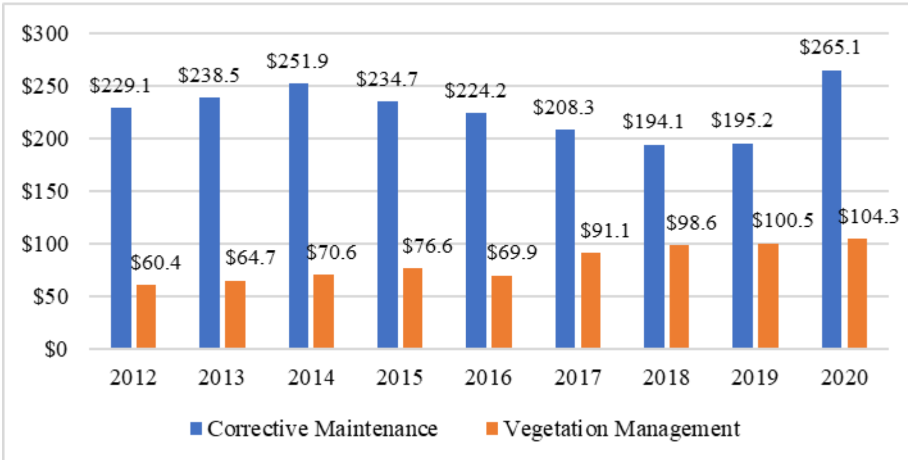
D. O&M

1. O&M Spending Overview

a. O&M Spend Categories Over $50 Million Annually

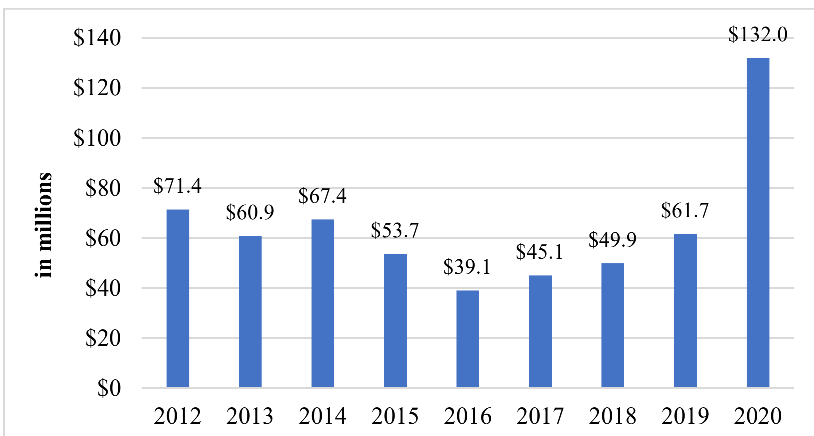
Two categories of significant O&M spend each year consist of Corrective Maintenance and Vegetation Management, with each exhibiting different spend patterns over the 2012 through 2020 period. Corrective Maintenance, the much larger spend category, showed early increased annual spend, then annual declines through 2017, followed by recent significant increases. Conversely, Vegetation Management spend, excepting 2016, showed steady annual increases, with 2020 spending 73 percent above that in 2012. The next chart summarizes O&M spending in the largest cost categories.

O&M Categories Over $50 Million Annually



The O&M portion of storm restorations were within the Corrective Maintenance O&M Category. Storm O&M spending substantially increased in 2020 due to the August derecho.

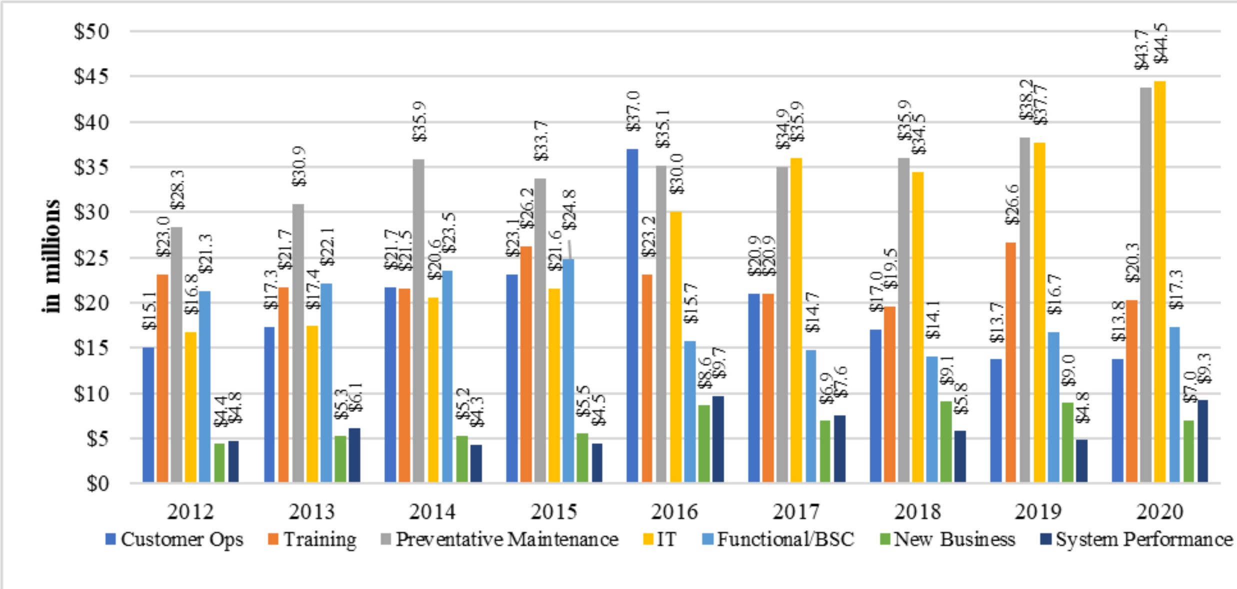
CM Storm O&M



b. O&M Categories Under $50 Million Annually

Seven O&M categories (summarized in the next chart) comprise the bulk of spending each year for category spend under $50 million annually. The categories include Customer Operations, IT, System Performance, Training, Functional/BSC (Exelon Business Services Company, LLC), Preventive Maintenance, and New Business. Generally, IT and Preventive Maintenance represented the largest annual categories of spend each year. Both have showed significant recent annual spending increases.

O&M Categories Under $50 Million



2. Corrective and Preventive Maintenance

Corrective Maintenance O&M (and capital plant) funding have a direct impact on distribution system condition and on preventing equipment-caused outages. Funding for CM goes to replace, and update aged, deteriorated, or obsolete distribution circuit and substation equipment and components, such as poles and substation transformers. O&M funded preventive maintenance, and O&M and capital funded corrective maintenance, serves to control outages caused by ComEd's distribution and substation equipment, much of which is very old, and some obsolete, such as some the 4kV substation equipment. See Chapter VI: *Distribution System Condition*, for descriptions of ComEd's inspection and maintenance programs.

a. Corrective Maintenance

ComEd spent over $2 billion between 2012 and 2020 for distribution corrective maintenance, including about $1.8 billion on the distribution system, $243 million on substations, and $30 million on the High Voltage distribution system. Annual CM O&M spending averaged about $227 million each year between 2012 and 2020, ranging from a low of $194 million in 2018 to $265 million in 2020.

b. Preventive Maintenance

ComEd conducts PM activities to address generally unseen conditions of distribution plant, HV distribution plant, and substation equipment, including periodic servicing, adjustments, and testing for condition issues. The company charged all PM work as O&M, which ranged from about $28 million in 2012 to about $44 million in 2020 for a total of about $317 million for the years 2012 through 2020. Distribution PM totaled about $145 million and substation and HV distribution PMs totaled about $171 million.

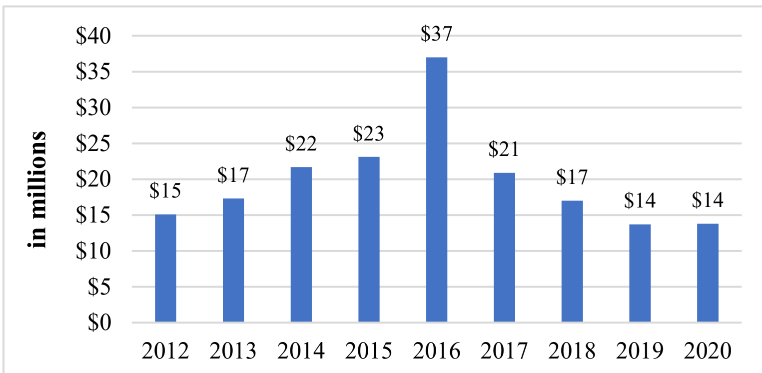
3. *System Performance O&M*

System Performance O&M spending totaled about $57 million from 2012 through 2020, with annual amounts ranging from approximately $4 million to about $9.5 million. Peak spending occurred in 2016 due to EIMA work and 2020 spending amounted to $9.2.

4. *Customer Operations*

Customer Operations and Customer Field Operations O&M spending totaled about $180 million for the study period. The next chart shows that the bulk of the customer operations O&M spend was related to implementation of the AMI system and Smart Meters that occurred in 2015 and 2016.

Customer Operations & Field Operations O&M



5. *Other Substantial O&M-Only Categories*

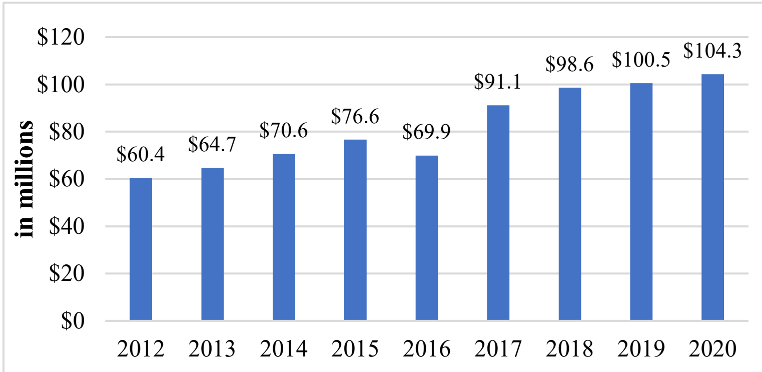
a. Training

Training of skilled lines, substation, and specialist workers is required to ensure the safety and effectiveness of overhead, underground, substation, communications, and relay work. ComEd spent between $20 million to $26 million on training each year during the study period, or a total of $203 million during the years 2012 through 2020 for the Training Category.

b. Vegetation Management (VM)

As described in Chapter VI: *Distribution System Condition*, VM comprises a core O&M program for electric utilities to prevents contact of trees and other vegetation with power lines. To supplement its legacy VM programs, in 2012, 2014, and 2017, respectively, ComEd implemented its Storm Hardening VM Program, its Grid Resiliency VM program, and its Emerald Ash Borer (EAB) Program. Its Storm Hardening Program continues, now included as part of normal operations and the EAB Programs should be completed in 2022. ComEd's VM O&M spending for the years 2012 through 2020 totaled about $737 million. The following chart shows a steady (excepting 2016) annual increase in VM spending with an approximate 73 percent increase in annual spend in 2020 compared to 2012.

Vegetation Management O&M



E. Impacts

1. Distribution O&M Spending and Capital Plant Additions

During the 2012 through 2020 study period ComEd spent approximately $4.2 billion for distribution O&M. Corrective Maintenance was the greatest single O&M expense during the period at approximately $2 billion, followed by Vegetation Management at $737 million.

During the study period, ComEd added approximately $10.7 billion for capital distribution plant additions, of which $3.8 billion was Distribution System Performance (reliability) plant additions and $2.9 billion was Distribution Corrective Maintenance plant additions.

2. SAIFI and CAIDI Reduction Initiatives

ComEd reported that it implemented CAIDI initiatives, including improved operation and technical methods for identifying the cause and location of outages, and for better preparation to manage and address outages immediately. SAIFI improved through enhanced animal protection and lighting mitigation programs. ComEd also completed its substation SAIFI recovery plan in 2018, including initiatives focused on substation wildlife fencing, circuit breaker overhauls, and bus inspections. ComEd reported that its efforts have avoided significant numbers of customer interruptions (CI).

Extreme weather-excluded SAIFI and CAIDI metrics bettered EIMA targets each year. (See Chapter VII: *Distribution System Performance*, for detailed descriptions of reliability performance.)

In addition, ComEd's system SAIFI, including the effects of storms, was 1.16 interruptions per customer in 2012, improved to 0.76 in 2016 and remained at that, or a slightly better level, through 2020, including the effect of the August 2020 derecho storm. ComEd's system CAIDI was 196 minutes in 2012 and improved to 105 minutes in 2019. The August 2020 derecho, however, caused the 2020 system CAIDI to increase to 440 minutes. ComEd reported that it excluding the August 2020 derecho would have produced a 2020 CAIDI of96 minutes per its calculations.

3. CI and CMI

SAIFI and CAIDI measure the number of annual interruptions and duration of those interruptions per average customer, respectively. Customer Interruptions (CI) and Customer Minutes of

Interruption (CMI) measure the total numbers of customer interrupted, by cause, and the total minutes of customer interruptions. CI and CMI are measures of the combination of reducing outage events and reducing the effect of outages on customers, by various outage causes. The major causes of CI and CMI during the study period, excepting weather related that depended on the annual impact of storms, were trees, overhead equipment, and underground equipment.

a. Distribution Corrective Maintenance Plant Additions

Rather than replacing aged portions of its 34,800 miles of overhead equipment, ComEd addressed reducing overhead equipment caused outages, and resulting CI and CMI, with significant overhead circuit visual and thermographic inspection programs, corrective maintenance programs, preventive maintenance programs, its worst performing circuits program, and customer targeted reliability programs.

A measure of the effectiveness of ComEd's overhead equipment corrective maintenance programs during the study period was the annual trend of improvement in overhead equipment related CI and CMI. Overhead equipment related CI reduced by 27 percent, and CMI reduced by about 45 percent. The improving trend of these CI and CMI measures over the study period suggests that the condition of ComEd's aged overhead distribution equipment was adequate, and because of ComEd's maintenance programs, along with improved distribution automation, provided improvement of ComEd's system performance over the study period.

Nearly half of ComEd's distribution system was underground, with 31,930 miles of underground distribution cable in 2020. Consisting mostly of aged facilities, the system commonly experienced failures early in our study period. However, the numbers of annual outages caused by underground cables and equipment failures has decreased by 48 percent since 2012, influenced by underground cable replacement programs initiated by EIMA. Following completion of the replacement program, CI caused by underground equipment failures have fallen by 55 percent and CMI by 61 percent, including the effects of the 2020 derecho.

b. Vegetation Management O&M Spending

Tree-related causes proved the greatest contributor to CI and CMI each year of our study period, except for 2020. Over that full period, tree-related CI dropped by about one-third but CMI increased by 43 percent. Vegetation management programs included enhanced tree trimming, hazard tree removals and, where trimming was not effective, by undergrounding specific segments or by installing tree resistant overhead spacer cable. ComEd's System Storm Hardening program included replacing about 400 miles of tree exposed overhead lines with underground cable, and installing about 510 miles of overhead tree resistant spacer cable.

c. System Performance Plant Additions

Distribution Automation (DA) can directly prevent some outages and indirectly influence others through enhance system visibility. However, the more significant contribution that DA devices and schemes make lies in reducing the numbers of customers affected by outages. The DA equipment included automatic circuit reclosers and self-healing smart grid schemes. Between 2012 and 2020, ComEd installed 4,382 automatic circuit reclosers, for a total of 7,444 reclosers. ComEd installed 1,257 "self-healing" smart grid schemes on its distribution circuits since 2012 for a total of 1,990 schemes by the end of 2020. Smart grid schemes automatically detect and isolate faults, use a smart algorithm to determine whether a second circuit can accept load and, if so, transfers the loads downstream from the faulted section to another circuit. Because they better limit the numbers of customer affected by a faulted circuit segment, smart grid schemes are most effective in reducing SAIFI and CAIDI system performance metrics.

The improvements in system performance resulting from ComEd's reliability programs during the study period, but primarily its applications of distribution automation including Smart Grids and other advanced sectionalizing and protection devices, are observed as substantially contributing to the annual reductions of equipment caused CI and CMI, as well as reducing the effects on customers from animal and lightning caused outages, and other weather caused outages. ComEd estimated that since 2012 the cumulative reliability programs, including the EIMA programs, avoided (prevented) over 15 million CI, at a rate of about two million CI each year, and avoided more than 200 million CMI each year until 2020, the year of the derecho, when 779 million CMI were avoided, as estimated by ComEd.

VI. Distribution System Condition

A. Summary

Chapter IV focused on system configuration, which changes over time largely because of capital expenditures made to replace equipment, make new service connections, increase power transfer capabilities to meet increasing peak loads, general load growth, provision for greater real-time condition awareness, and accelerate system response to threat conditions. This chapter addresses the conditions to which management seeks to manage system assets (under the commonly applied term of "Asset Management"). This "care and feeding" tends more to require O&M expenditures for preventive maintenance (and sometimes replacement), inspections and resulting corrective maintenance (which produces material capital spending as well), needs identification and completion, and vegetation management, to name some of the principal contributors.

Principal observations about system condition during the 2012 through 2020 study period include:

- While not a dispositive indicator of condition, the industry considers equipment age and aging trends one marker to consider. Based on our experience, ComEd operates a high amount of aged equipment, and ages in some classes of equipment grew over our study period. ComEd spent considerable amounts on a typical range of programs and initiatives to maintain the condition of its distribution circuit and substation equipment.
- The system performance data we collected and analyzed (see Chapter VII, *Distribution System Performance*) show steady reductions in customer interruptions (CI) and customer minutes of interruption (CMI) caused by overhead and underground equipment. Overhead equipment related CI decreased by about 27 percent and CMI decreased by about 45 percent. Underground equipment related CI and CMI decreased by 55 percent and 61 percent, respectively.
- Annual capital additions to plant from Corrective Maintenance ran at a roughly $310 million pace until an increase to about $408 million in 2020, driven largely by the August derecho. (See Chapter V, *Capital Investment and O&M Spending*).
- ComEd averaged about $195 million per year in O&M distribution and high voltage distribution circuit preventive maintenance and corrective maintenance from 2016 through 2019. Spending increased significantly in 2020 to $260 million, again coincident with the August 2020 derecho. It spent about $9 million each year from 2016 through 2020 for distribution substation preventive maintenance.
- We found inspection and maintenance programs are comparable to other utilities whose practices we have examined, for example:
  - Two-year cycle for distribution mainline circuit patrol and thermographic inspection
  - Four-year cycle for lateral circuits tapped from the mainline circuits
  - Risk-based prioritizing and scheduling of corrective maintenance tasks
  - Ten-year wood pole inspection, treating, and weak pole removal program
  - Time-based, operations-based, and condition-based based preventive maintenance (servicing, adjusting, and testing) programs for distribution circuit and substation equipment
  - Distribution and substation equipment condition health scoring process to adjust equipment maintenance programs and to determine equipment end of life.

- Underground equipment inspection programs and EIMA and non-EIMA underground mainline and underground residential distribution (URD) cable replacement and injection programs coincided with 2012 through 2020 reductions in numbers (CI) and in minutes (CMI) of 55 percent and 61 percent, respectively.
- ComEd increased vegetation management O&M spending from about $60 million in 2012 to about $104 million by 2020. Vegetation management program expenditures over the period (including EIMA enhanced trimming and hazard tree removal programs, and the installations of underground cable and tree-resistance overhead cable) were accompanied by a reduction of 37 percent in CI and an increase of 43 percent in CMI attributed to tree-related causes.
- ComEd addressed distribution system resiliency by removing weak, decayed poles, installing stronger new poles and cross arms, enhancing tree trimming, conducting programmatic hazard tree removals, and improving distribution automation. Chapter VII, *Distribution System Performance*, describes overall "weather-related" CI and CMI reductions from 2012 through 2019, with an apparent derecho-related increase in 2020.

B. Asset Age

Substantial aging characterizes much of ComEd's distribution plant. Factors causing deterioration as equipment ages include corrosion, solidified lubrication, weathering, heat, water contamination, decay, insects, UV radiation, and worn parts. Deterioration has many forms such as stuck moving parts, malfunctioning relays and circuit breakers, electric tracking on insulators, weakened insulation, overheated connections, and broken wires, poles, and cross arms. ComEd applied a variety of inspection, servicing, maintenance, testing, equipment rehabilitation, and health monitoring practices to mitigate the effect of deterioration.

The ageing of ComEd's legacy equipment reinforced the need for comprehensive and effective inspection and maintenance programs, including replacing wood poles, substation transformers, and circuit breakers when inspections, testing, and operating issues indicate the need to do so. ComEd had replaced some aged equipment for condition and operating issues and installed new equipment for capacity expansion and for reliability programs. Nevertheless, the median age of ComEd's major overhead and substation plant overall increased since 2012. ComEd reported that the median age of its copper overhead distribution conductor reached about 60 years in 2012 and 66 years in 2020, with over 40 percent more than 60 years old. The median age of ComEd's direct buried underground residential distribution (URD) cable reached about 17 years in 2012 and 23 years in 2020, even though ComEd replaced much of its direct buried URD cable with new higher quality cable during the study period.

In 2012, the median age of ComEd's 1.4 million wood distribution poles reached about 44 years with about 170,0000 of those poles over 60 years old. In 2020, the median age of wood poles increased to about 49 years old with about 370,000 poles over 60 years old, and about 110,000 of those over 70 years old.

About 43 percent of ComEd's 12kV transformers, 21 percent of its 34kV transformers, 40 percent of its 69kV transformers were over 60 years old with a few transformers over 90 years old. About 16 percent of all circuit breakers were over 60 years old, and about 70 of the 4/12kV breakers primarily in the Chicago and North Regions were over 90 years old. The ages of about 8 percent of 4kV and 12kV circuit breakers could not be identified.

C. Asset Management Policies

ComEd had formal asset management policies during the study period. ComEd's asset management policies described Predictive Maintenance (PdM), Preventive Maintenance (PM), and Corrective Maintenance (CM) programs as intended to maintain distribution circuits and substation equipment in a condition conducive to support achievement of operating and performance goals.

PdM identifies equipment condition by visual inspections and, with visual not practical, by diagnostic tests. Tests, for example, include infrared thermography (for hot spots), insulating oil tests and dissolved gas-in-oil analysis, various transformer insulation tests, acoustic monitoring, and circuit breaker timing tests. PdM data triggers PM or CM activity when maintenance frequency warrants modification for a specific system component. PM activities, such as adjusting and calibrating components, cleaning and lubricating circuit breaker and switch mechanisms, and conducting predictive tests, usually pre-planned, employ periodic time-based servicing of equipment designed to prevent deterioration and in-service failures. However, PM activities could result from a specific event or a system equipment condition. ComEd's corrective maintenance (CM) activities applied priorities based on risk to safety and reliability to timely correct equipment defects to support maximizing equipment and system reliability and to meet regulatory requirements. The programs and policies focus on safety, hazard recognition, and mitigation.

ComEd's predictive and preventive maintenance policies sought to develop, implement, and document asset maintenance programs designed to support maximizing equipment life and system reliability in accord with applicable requirements and regulations. ComEd's long-term PM strategy included measures to monitor equipment performance, to identify known equipment failure modes, and to evaluate and process feedback using equipment operating, manufacturer, and industry experience. The strategy called for PM task and frequency adjustment based on system and component reliability.

D. Maintenance Planning

ComEd developed long-range PM and CM O&M and capital budgets and resource estimates based on historical trends and identified specific needs. O&M funding covered preventive maintenance funding, with corrective maintenance funded either as O&M or capital plant, depending on circumstances. As described in Chapter X, *Distribution System Planning*, the capital screening and authorization processes for corrective maintenance followed screening, review, challenge, and authorization processes similar to those used for capacity expansion planning.

The Work Management and the Training Departments determined the numbers and skills of field resources required and need for additional training. ComEd generated work orders describing the work for each component using specialized software programs. ComEd scheduled and recorded work tasks and the completion dates each week. To provide efficiency, ComEd bundled outage-required PM and CM work within functional equipment groups.

The Work Management organization had responsibility for evaluating resource requirements and for developing long-range work and resource plans and resource strategy for plan execution. Distribution System Operations, Construction and Maintenance, and Transmission and Substation Directors, Managers, Supervisors, and Work Planners were responsible for providing skilled resources and for ensuring completion of day-to-day PM and CM work activities, and for consistency with PM and CM maintenance policies and procedures.

The Engineering organizations supported field operations by identifying equipment failure modes, monitoring failure trends, and working with the manufactures. They also prescribed the preventive maintenance programs task requirements and frequencies, and they conducted periodic maintenance program performance audits using specialized maintenance tracking programs. Engineering also examined the inspection and testing results to determine when non-programmed PMs were necessary to investigate deteriorated conditions. Engineering also approved any modifications to the programs, considering equipment expert and manufacturer recommendations, and new technologies.

E. System Inspection and Maintenance Programs

An electric system maintenance program should: (a) ensure that equipment receives timely service as required for continued safe operation, (b) identify equipment deficiencies before failure by inspection or testing, (c) ensure timely correction of defects, and (d) provide equipment condition data for predicting risk of failure, and (e) provide justification of equipment replacement.

ComEd allows a grace period beyond a prescribed due date - - typically the lesser of 25 percent of the task performance interval or four years. This timeframe allows work outage scheduling flexibility and permits work bundling opportunities.

1. Distribution Circuit Inspections and Corrective Maintenance

During the study period, ComEd employed a circuit inspections and corrective maintenance (CM) program. ComEd visually inspected distribution circuits and substations for condition monitoring purposes and to identify and prioritize repairs. From 2012 through 2015, ComEd inspected mainline circuits and lateral circuits tapped off the mainline circuits on four-year cycles. From 2016 through 2019, ComEd inspected mainline circuits on two-year cycles and lateral tap circuits on six-year cycles. ComEd began in 2020 to inspect its 4kV and 12kV mainlines on two-year cycles and its lateral tap circuits on four-year cycles. ComEd inspected its 34kV circuits on two-year cycles and its 69kV circuits on an annual cycle. These inspections included cross arms and braces, lightning arresters, disconnect switches, cutout fuses, fault indicators, pins, and guy wires. ComEd reported that it had annually inspected all circuits, consistent with its program, during the study period. A contractor conducted thermographic (infrared) inspections on every mainline circuit on two-year cycles. The purpose of the thermographic inspections was to identify overheated connections and splices. Asset Management engineers verified inspection and CM completions on a monthly cycle.

ComEd's maintenance inspectors, using handheld devices for tracking the inspections and a laptop computer for reporting deficiencies (CMs), conducted the periodic and post-storm drive-by and walking patrol inspections of the 4kV, 12kV, 34kV, and 69kV circuits. They also repaired minor-ground level issues identified, such as broken ground wires and missing guy guards and ground wire molding. The inspectors also called for tree trimming when they observed tree limbs about to contact conductors. Reliability engineers conducted ad hoc circuit inspections to address CERT (customers exceeding reliability targets) cases and to investigate outage causes for the One Percent Worst Performing Circuits.

ComEd inspected underground vaults and transformers on cycles that depended on criticality. It inspected vaults at airports every three months and at other locations on 6-, 12-, or 18-month cycles. It inspected and calibrated secondary network protectors on one-to-five-year cycles.

ComEd prioritized distribution circuit corrective maintenance (CM) tasks identified by inspectors, and it set recommended CM completion time limits based on prioritization category. The next table summarizes distribution circuit CM priorities and recommended completion time limits. ComEd allowed a grace period of one-quarter of the repair-by-time beyond the prescribed maintenance due date to allow for scheduling efficiency.

ComEd CM Priority Table

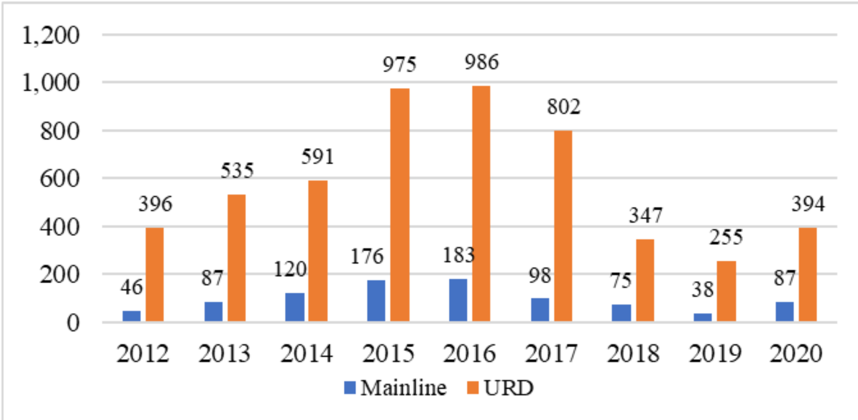
Priority	Condition	Repair-By Time
P10	Critical – High Impact	Immediate response required; work item 24/7 until complete or until compensatory actions allow downgrading the priority
P20	Possible High Impact	2 to 4 weeks
P30	Moderate Impact	9 months to 1 year
P40	Low Impact	Bundle with other work; shall not exceed 1 year past the predominant maintenance cycle

ComEd's end-of-year open distribution CM backlogs between 2012 and 2020 held steady at about 20 open CMs each year for high impact P10 CMs and about 200 open CMs each year for possible high impact priority P20 CMs. ComEd had been working down its large backlog of lower priority distribution CMs since 2012. ComEd's end-of-year backlog of open moderate impact P30 CMs decreased from about 17,000 in 2012 to about 8,000 in 2020. Its end of year backlog of open low impact CMs decreased from about 57,000 in 2012 to about 12,500 in 2020. End-of-year backlogs do not necessarily indicate overdue CMs, but the large numbers of lower priority CMs reflect equipment age issues and the amount of CM completion work required by ComEd's rather intense inspection schedules.

2. *Underground Distribution Proactive Cable Replacements and Failures*

Underground cables comprise nearly one-half of distribution circuit mileage. During the study period, ComEd substantially improved the condition of its underground facilities. ComEd employed a program for replacing, or injecting a filler fluid, into its worst performing mainline cables and underground residential distribution (URD) cables, as this chart summarizes.

Miles of Mainline and URD Cable Replaced or Injected

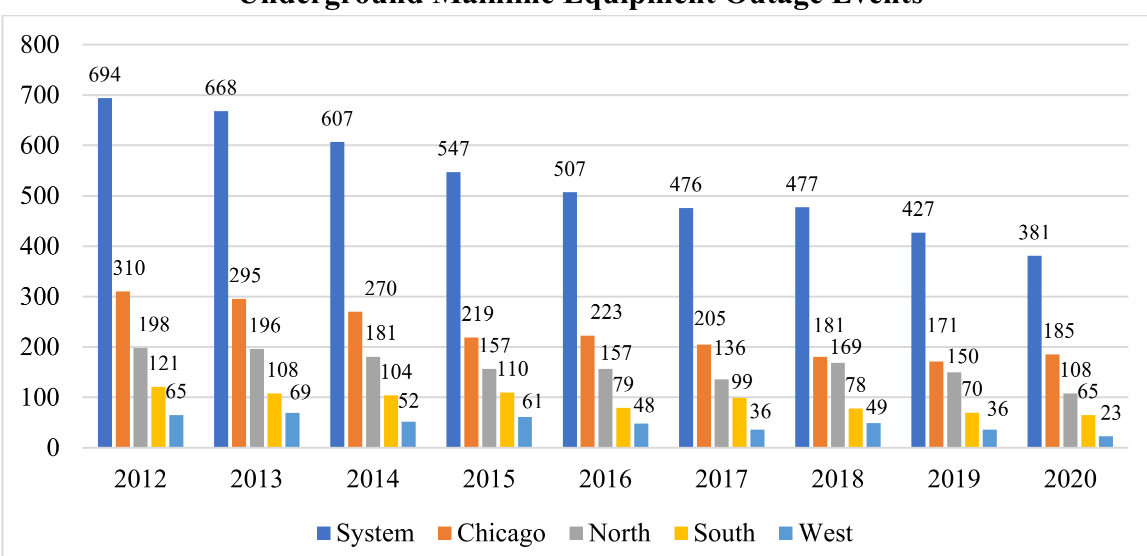


Injecting cables to fill voids proved less expensive than replacing cables. However, ComEd stopped injecting cables in 2016 because of application limitations. It had injected 412 miles of URD cable during the study period. Note that ComEd reported that its numbers of URD miles reported here differ from data reported to the ICC (differences include URD miles of 470 in 2012 and 461 in 2013).

c. Mainline Cable Caused Outage Events

Mainline underground circuits ran from substations to underground service transformers, secondary networks, and to underground residential distribution (URD) networks. Although mainline underground cable outage events occurred much less frequently than did overhead outage events, mainline cable outages resulted in larger numbers of customer interruptions and longer restoration times. As poor performing mainline cable was replaced, the annual numbers of underground mainline equipment outage events declined during the study period, as the next chart summarizes. As depicted below, we found that regional mainline underground equipment caused outages, including cables, had occurred in proportion to mileage of mainline cable in each region.

Underground Mainline Equipment Outage Events

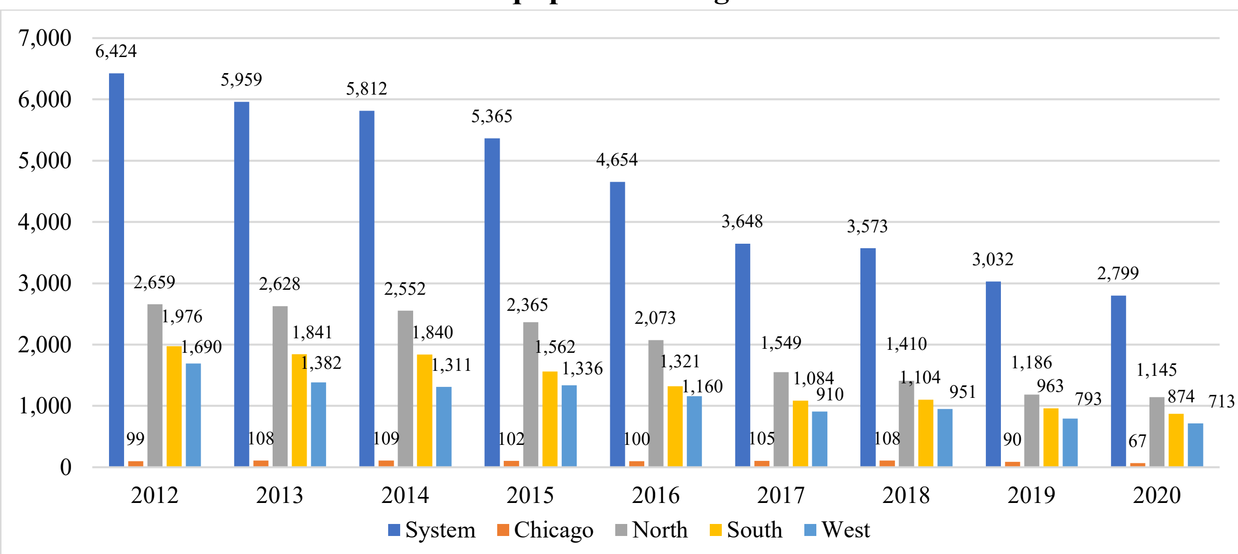


d. Underground Residential Distribution Cable Caused Outages

During the study period, ComEd reduced the annual numbers of URD cable caused outages. URD cables were historically buried to serve primary (high voltage) circuit loops for residential and commercial customers. The cables installed in the 1960s through the 1980s employed insulation susceptible to water contamination, resulting in electrical failure. Their exposed bare concentric neutral conductors in many cases corroded and dissolved, causing possible hazardous stray currents in the earth. ComEd's legacy practice consisted of replacing failed URD cable sections after two or three failures in two years.

An individual URD cable outage may not have produced a significant reliability impact, but large numbers of URD cable outages degraded overall reliability metrics significantly. The following chart shows that ComEd's URD replacement program has substantially reduced the numbers of URD caused outages since 2012. We found regional URD cable failures proportional to mileage per region, except for the North Region, which had a greater per mile URD failure rate.

URD Equipment Outage Events



3. Distribution Circuits Preventive Maintenance

During the study period, ComEd employed an overhead distribution preventive maintenance program. ComEd serviced its overhead automatic circuit reclosers based on numbers of operations, but at least every ten years. It serviced voltage regulators every year and its automatic transfer operators (ATOs) every even year and calibrates the ATOs on every odd year. ComEd indicated that it had completed its distribution PMs consistent with program schedules.

4. HV Distribution and Substation Inspections and Corrective Maintenance

In 2020, ComEd served 92 high voltage distribution (HVD) customers directly from the 69kV and 138kV transmission systems. During the study period, ComEd inspected and maintained HVD lines under its transmission circuit inspection and CM programs. ComEd annually conducted aerial visual and thermographic (infrared) inspections of accessible overhead lines. ComEd transmission crews also conducted annual walking inspections of those portions of transmission lines not accessible by helicopters, such as in urban areas. ComEd included inspections of its 69kV circuits with its distribution system inspections. ComEd scheduled underground transmission circuit outages on 4-year cycles. During these outages, underground transmission crews inspected cable joints (splices) and associated equipment and the crews either repaired defects immediately during the outage, or within six months. Asset Management verified inspection and CM completions monthly.

ComEd completed about 35,000 substation inspections each year during the study period. ComEd's area operators, who conduct switching in the substations, formally inspected large critical substations on 5-week cycles, and the smaller substations on 10-week cycles. A contractor conducted annual thermographic inspections of all substation connections. ComEd dispatched Fix-It-Now (FIN) crews to timely address emergent conditions, *e.g.*, an oil leak identified as requiring immediate attention. Otherwise, inspectors assigned CM priorities to the follow up CM work identified. ComEd's prioritized high voltage (HV) distribution and its substation CMs the same as it did for distribution CMs. (See the table located above titled "ComEd CM Priority Table.")

ComEd combined transmission CMs with its substation CMs. During the study period, ComEd was generally working down its end-of-year T&S backlogs. The large numbers of lower priority CMs reflected equipment age issues and the amount of CM completion work produced by ComEd's inspection schedules. The end-of-year open T&S CM backlogs approached zero each year for high impact P10 CMs and about 75 open each year for possible high impact priority P20 CMs. Efforts to work the large number of backlogged low-impact P40 CMs brought them from 10,522 CMs at the end of 2012 to 3,016 CMs at the end of 2020. However, moderate impact T&S P30 increased from 441 open CMs at the end of 2012 to 988 open CMs at the end of 2020.

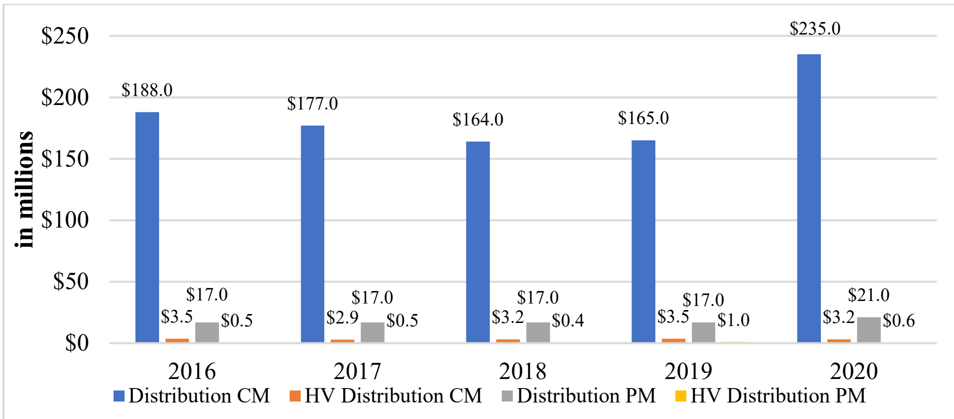
5. Substations Preventive Maintenance

During the study period, ComEd employed a substation equipment preventive maintenance (PM) program. ComEd conducted major PM on large transformers on eight-year cycles and on smaller transformers, under 10MVA, on 8- to 16-year cycles, employing the grace period described previously. PMs include servicing fans and pumps, calibrating gauges, and testing transformer insulation, windings, and bushings. Transformer oil was sampled on one-year cycles for quality tests, and transformer oil was sampled for dissolved gas analysis (DGA) on 3- to-12-month cycles, depending on transformer size. DGA was the major means to monitor transformer winding insulation condition. Many large transformers employ DGA monitors that alert operators of internal condition issues. ComEd conducts major PMs on its circuit breakers on 3-year to 8-year cycles, depending on type and operating voltage. Circuit breaker maintenance includes servicing, time travel analysis, and contact resistance. ComEd serviced and tested protective relays and tripping schemes on 4-year cycles for transmission relays and on 6-year cycles for distribution relays.

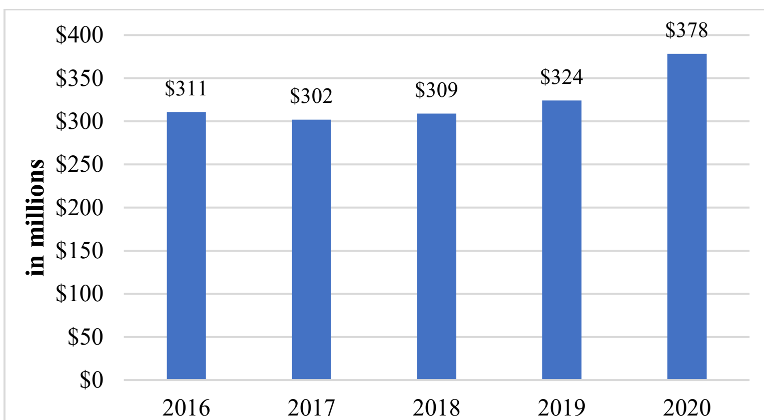
6. Distribution CM and PM and Capital Plant Additions (2016 – 2020)

ComEd increased its O&M spending and capital plant additions for distribution maintenance in 2020, compared with the previous four years. The following two charts depict ComEd's 2016 - 2020 Capital Plant additions and O&M spending for corrective maintenance (CM) and preventive maintenance (PM) for its 4kV, 12kV, & 34kV distribution systems, as well as for the 69kV and 138kV HVD systems that directly serve customers. The O&M spending covers driving, walking, and aerial inspections and HVD switch operation and lubrication., ComEd's O&M spending and capital plant additions for distribution CMs and PMs remained relatively flat during this period, except in 2020, when its O&M spending increased by 40 percent compared to 2019 and its capital plant additions by 17 percent, compared to 2019, possibly due in part to the August 2020 derecho storm. The next two charts summarize Distribution O&M and capital plant additions for corrective maintenance (CM) and preventive maintenance (PM) of the distribution system from 2016 through 2020.

Distribution CM and PM O&M



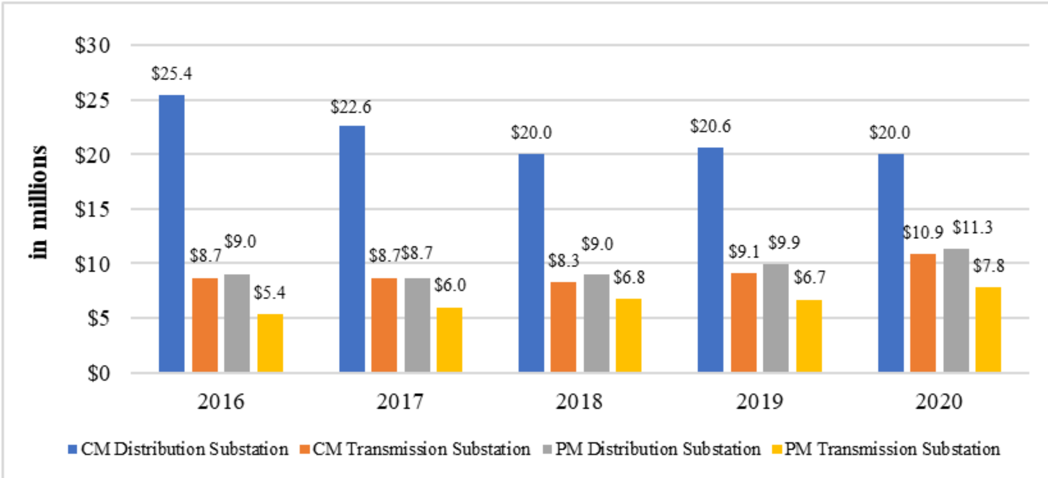
Distribution & HV Distribution CM Plant Additions



7. *Substation CM and PM and Capital Plant Additions (2016-2020)*

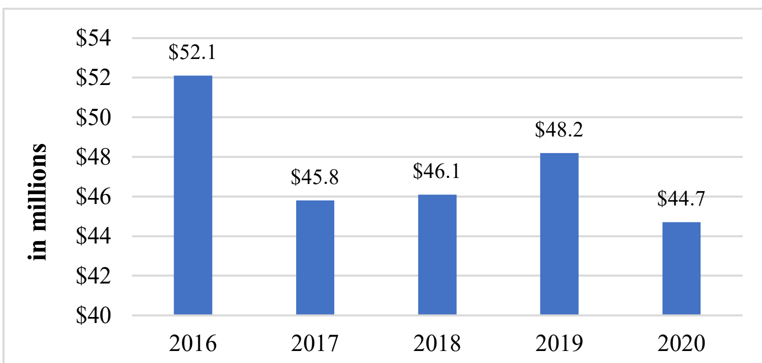
The following chart shows that the annual O&M spending for distribution substation corrective maintenance (CM) decreased since 2016, but remained relatively steady since 2018, and that annual O&M spending for substation preventive maintenance (PM) increased over the same period.

Substation CM and PM



The next chart shows that corrective maintenance capital plant additions for substations decreased following 2016 but remained relatively steady thereafter through 2020.

Transmission & Distribution Substation CapEx



F. Distribution System Health Assessment Process

ComEd proactively monitored the condition of its distribution and substation equipment. During the study period, ComEd's Asset Management organization applied its Health Indexing process to evaluate distribution system equipment and identify age- and operations-related condition issues. This process applied numerous criteria to qualitatively determine asset condition, to assess failure risk and to determine equipment end of life, and to assess the consequences of allowing equipment to run to failure. ComEd used Health Indexing as the basis for its Material Condition Improvement Plan (MCIP). The MCIP process used risk modeling to assess risk and consequences, based on health indexing, to prioritize and to invest in targeted distribution equipment classes expected to provide the greatest cost benefit. For example, ComEd's URD cable replacement program during the study period targeted poor performing URD cables installed from 1966 through 1985.

ComEd implemented in early 2019 its distribution health assessment (DSHA) project, which included investigations of ten elements of the distribution system by teams of ComEd and external experts, to further evaluate distribution system condition. These investigations sought to identify the effect of plant conditions and practices on reliability and resiliency, to identify improvement opportunities, and to develop enhancement recommendations. The assessment organized across ten areas of the distribution system, including underground cable, distribution poles, fused cutouts, lightning arresters, broken and downed wires, distribution automation, device communications, underground switchgear, vegetation, and underground networks. ComEd reported that it continues to review, update, and expand its health assessments.

ComEd also employed programs that sought to determine systematically ends-of-life for major capital substation equipment. Asset management, substation engineering, and equipment specialists monitor the condition of major substation equipment quarterly, including transformers, circuit breakers, and switches. An algorithm develops a health score from 1 to 100, with a score of 1 to 20 representing "poor" health. The scoring system operated as follows:

- Very Poor 0-20
- Poor 20-40
- Fair 40-60
- Good 60-80
- Very Good 80-100

Operating, maintenance, and testing data, weighted by the consequences of failure (*e.g.,* operability of the system and customer interruption and durations) and on the costs required to improve condition and to continue applying corrective maintenance drove these health scores. Management performed emergency correction or replacement was applied to equipment identified as subject to imminent failure. Otherwise, the long-range capital planning process addressed replacement of equipment items with low health scores. Based on low health scores, ComEd proactively replaced 50 substation transformers and 1,487 circuit breakers during the study period.

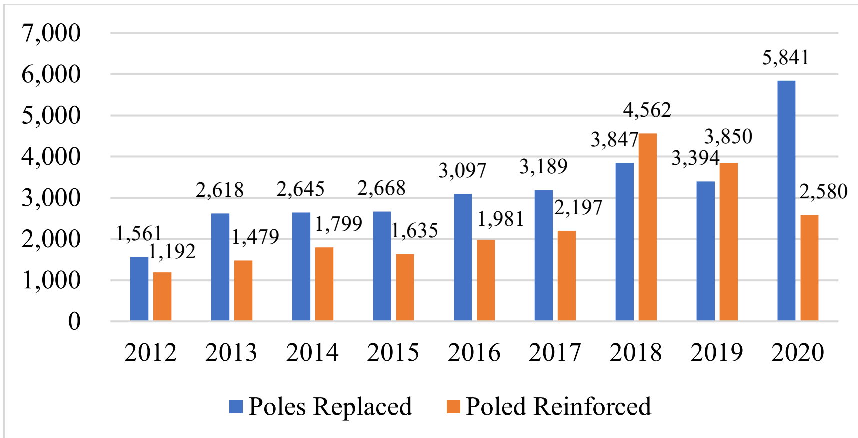
G. Wood Pole Groundline Wood Pole Program

ComEd proactively removed excessively decayed distribution poles and treated other poles to extend pole life. Weak wood poles threaten safety and break more easily during storm events, extending restoration times. Chemically treating poles of adequate strength but with internal voids caused by insects and fungus comprises a broadly used practice to extend pole lives. Wood pole strength reduces over time, depending on factors such as tree species, soil conditions, insect infestation, decay from fungus, and preventative chemical treatments. Wood pole inspections, called groundline inspections, determined pole strength by sounding poles with a hammer to identify internal voids, by boring into poles above and below the groundline, and by measuring the thickness of pole shells between internal voids and the pole exteriors. The measured shell thickness determined pole strength. If the pole strength did not meet National Electrical Safety Code (NESC) guidelines, ComEd replaced or reinforced the poles with steel to add sufficient strength. ComEd applied fungicides to poles with internal voids, but that had adequate strength, to reduce further decay.

ComEd employed a groundline pole inspection program to maintain its aged wood pole plant. ComEd implemented the new practice of replacing weak poles, and all new poles, with poles having greater diameter (stronger) than the poles it historically installed. These larger poles have longer life and can better withstand the forces of windstorms, ice, and fallen trees. The median pole age will continue to increase as pole replacements average less than 1 percent per year of the total pole population.

ComEd's electric system included about 1.3 million wood poles in 2020. ComEd conducted groundline pole inspections on 10-year cycles, producing about 149,000 inspections, including transmission poles, each year. The next chart shows the numbers of transmission and distribution wood poles replaced or reinforced each year as generated by those inspections (*i.e.*, not including work due to storms, public damage, or designed activities) during the study period.

T&D Poles Replaced and Reinforced



H. Vegetation Management Programs

During the study period, ComEd continued its standard tree trimming practices and enhanced those practices to reduce the numbers of tree related outage events. ComEd's Vegetation Management (VM) organization was responsible for the development, documentation, and budgeting of vegetation management programs. At locations where tree trimming practices do not offer the best long-term solution to prevent tree-caused outages, ComEd installed tree-resistant overhead cable and it undergrounded circuit segments. It installed 255 circuit miles of tree-resistant overhead cable, including 23 miles in the Chicago Region, 55 miles in the North Region, 101 miles in the South Region, and 76 miles in the West Region.

Standard trim clearance distances between tree limbs and overhead primary conductors depend on tree species and growth rates. For example, silver maples have very fast growth rates and oak trees have slow growth rates. ComEd trims tree limbs three to ten feet from the outer sides of the 4kV and 12kV conductors, and six to fourteen feet from the outer sides of the 34kV conductors, under its legacy 4-year cycle distribution circuit vegetation management program. ComEd trims overhanging limbs six to ten feet from the 4kV and 12kV conductors, and it removes all overhanging limbs above the 34kv conductors. It trims limbs 6 to 14 feet under the 4kV and 12kV conductors and to six to fourteen feet under the 34kV conductors.

To supplement its legacy VM programs, ComEd implemented its Storm Hardening VM Program (2012), its Grid Resiliency VM program (2014), and its Emerald Ash Borer (EAB) Program (2017). Its Storm Hardening Programs now forms part of normal operations and the EAB Programs should be completed in 2022. ComEd spent approximately $12 to $14 million each year between 2017 and 2020 for the EAB tree removal program.

ComEd determined whether to apply engineered storm hardening solutions or enhanced storm hardening vegetation management solutions to address outages for customers experiencing the most frequent and long-lasting outages. Circuits targeted included those whose customers experienced seven or more outages, or 18 hours of outage per year during the previous three years.

ComEd applied its vegetation storm hardening program as the vegetation management solution to reduce storm-related damage and outages from 2012 through 2017. This program included removing overhang and additional trimming to increase conductor-to-tree clearances and removing hazardous trees in and outside the normal trim. ComEd completed 806 miles of storm hardening vegetation work on 793 circuits. This storm hardening vegetation management work combined with engineering solutions to reduce the numbers of customers exceeding the three-year frequency and duration thresholds from over 18,000 in 2012 to 14 in 2017. ComEd continued the vegetation storm management hardening program as part of normal operations after 2017.

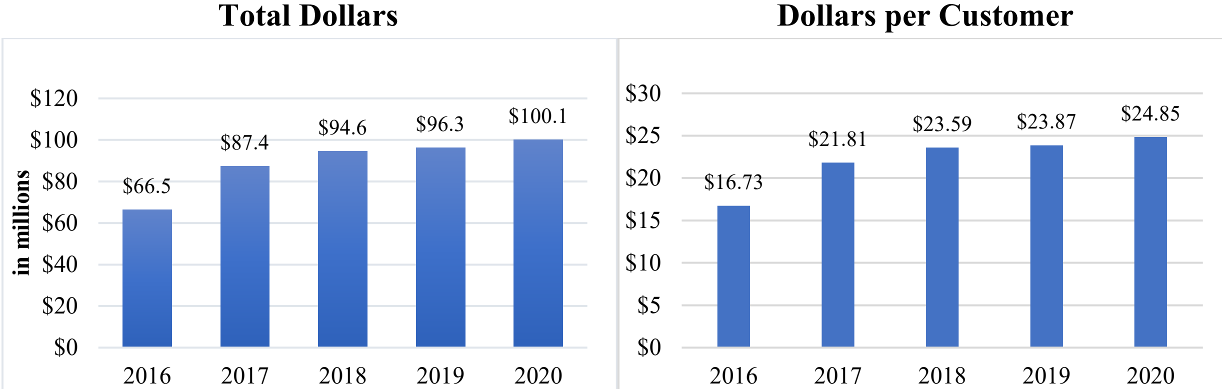
ComEd's 2014 to 2018 vegetation management grid resiliency program provided enhanced trimming beyond the standard tree clearance trimming and removal of hazard trees. This program targeted trees most likely to cause interruptions due to species, condition, and proximity to the power lines. Reliability engineers targeted circuits based on tree risk scoring. Risk scoring included numbers of customers served, overhead mileage, past performance, and numbers of customers experiencing seven outages over the past two years. Enhanced trimming included additional clearance for re-growth, removing overhead branches, and removing trees where trimming alone did not mitigate risk. Between 2014 and 2018, ComEd conducted 13,389 enhanced tree trims on about 183 miles of line segments on 73 circuits and removed 27,835 trees. Total O&M spending for this program ran to $14.2 million.

From 2013 to 2019, ComEd combined the efforts of its vegetation management and marketing organizations to provide a comprehensive vegetation management awareness program to improve customer perception and acceptance of vegetation management work that may affect them. Program attributes included improved employee and customer communications, partnerships with corporations and municipalities, and vegetation management specific materials and web-based communications addressing the benefits of the vegetation management work. Customer studies indicate that customer satisfaction related to trees substantially improved after 2012.

Vegetation Management activities affected 34,805 miles of right-of-way encompassed by 8,765 overhead circuits. Between 2016 and 2020, ComEd trimmed one-quarter of these circuits on an annual basis as required by its programs. The next two charts depict ComEd's O&M spending, and costs per customer for these distribution vegetation management programs between 2016 and 2020.

Vegetation Management O&M

Total Dollars **Dollars per Customer**



VII. Distribution System Performance

A. Summary

We know of no way to isolate the benefits discretely added by particular programs or classes of distribution system expenditures or for that matter to quantify specific performance declines resulting from particular performance or expenditure gaps. Moreover, our scope did not include an attempt to assess whether expenditures in the past produced or did not produce value of equal magnitude. Nevertheless, we have been tasked with identifying benefits obtained across the study period. For distribution system capital and O&M programs, projects, and initiatives, we consider an examination of tangible distribution system performance measures a sound means for providing a holistic, yet defensible assessment of what all those sources of resource commitments have done in providing benefits.

Beyond that, one can also, as we have done in other chapters, compare the programs, projects, and initiatives ComEd has undertaken and the rationales they have used to support them with what we have seen elsewhere. To the extent that the programs, projects and initiatives comport with what we have seen used elsewhere, with results that we consider positive, that consistency offers another perspective on benefit - - others have acted similarly and with positive results. We have found, as explained in other chapters of this report, ComEd has pursued system performance improvements through accepted practices and initiatives. As this chapter describes, we found that performance improved through the expenditures on which ComEd has principally focused.

Again, we were not asked to assess, nor do we answer questions about, whether funds could have been used to better purpose elsewhere or even spared from expenditure altogether. The same is true of trying to equate dollars spent with value of benefits produced. We stop, with respect to distribution system expenditures, at concluding that dollars spent, which by any measure have been substantial, have produced benefits that are reasonably broad ranging and material. As we hope Chapter VIII, *Advanced Metering Infrastructure*, makes clear, the scope of the program it addresses, while large in its own right, makes it more easily addressable in at least substantial isolation from other programs, projects, and initiatives.

We made the following overall observations about ComEd distribution system performance during the 2012 through 2020 study period:

- System and regional reliability metrics improved through the 2012 through 2020 period. EIMA storm-excluded system SAIFI decreased (improved) by about 41 percent and System CAIDI decreased by about 18 percent.
- Including storms, system SAIFI decreased by better than 34 percent by 2020, and system CAIDI decreased by 46 percent by 2019. CAIDI substantially increased in 2020 because of the August derecho.
- ComEd's system-wide SAIFI and CAIDI metrics were among the best when compared to 24 similar IEEE peer group utilities, and better than the year-to-year EIMA storm-excluded SAIFI and CAIDI target metrics.
- The greatest causes of customer interruption (CI) and customer minutes of interruption (CMI) during the study period were trees, equipment malfunctions, and weather. During the study period:
    - Tree-related CI declined by one-third but CMI increased by 43 percent

- Overhead equipment-related CI declined by one-quarter and CMI declined by one-half
- Underground equipment-related CI and CMI both declined by one-half
- Weather (storms and lightning) related CI and CMI both declined by three-quarters, until the August 2020 derecho storm
- Animal caused CI and CMI declined by two-thirds.

- ComEd reduced equipment caused outages during the study period by maintaining the condition of its distribution circuit and substation equipment. It reduced the number of tree-caused outages by enhancing tree clearances and removing hazard trees, by applying some system resiliency improvements, *e.g.*, installing stronger poles, and undergrounding some tree exposed overhead wire. Management also enhanced lightning and animal protection.
- Installation of substantial numbers of distribution automation "Smart Grid" automatic circuit load transfer schemes and improved substation protective schemes, circuit protective device coordination, and lateral tap circuit protection, reduced the number of customers interrupted and minutes of interruption from each outage.
- Reliability benefits of distribution automation have shown in CI and CMI reductions due to weather, equipment, tree, and animal causes.
- Some customers experienced excessive outages or excessive minutes of interruption that did not substantially impact the System reliability metrics. ComEd addressed these "pocket customers" by taking mitigating actions included in its one percent worst performing circuits (WPC) and its customers exceeding reliability targets (CERT) programs. These pocket reliability mitigation practices included replacing poor performing overhead conductor, installing automatic circuit reclosing and load transfer devices, addressing tree issues, installing fiberglass cross arms, replacing overhead open conductor with tree resistance spacer cable, and installing underground cables to mitigate tree contact.
- ComEd reported reductions in the numbers of CERT customers from over 18,000 in 2012 to 11 in 2018, increasing to 53 in 2019. However, the system number of CERT customers increased to 649 in 2020 and 636 in 2021. Almost all CERT customers were in the South and West Regions.
- Other than for CERT and WPC programs, and those required by regulatory agencies, ComEd indicated that it selected its reliability improvement programs, (*e.g.*, smart grids) based on the ratio of the greatest reliability benefits to cost. It weighed the costs of programs against the ability to avoid customer interruptions (CI), customer minutes of interruption (CMI), and outage frequencies and durations. It also developed estimates of CI and CMI avoided (prevented) each year post-completion of the reliability and resiliency programs.
- EIMA and non-EIMA programs contributing to the declining SAIFI, CAIDI, CI, and CMI metric during the study period included:
  - Additional distribution automation devices, communications, and schemes
  - Improved troubleshooting and restoration processes
  - Improved animal protection and lightning identification
  - Improved substation relaying and communications systems
  - System hardening and resiliency programs and projects including stronger poles and substation flood walls

- Poor performing underground cable replacements
- Replacing weak decayed poles
- Enhanced vegetation management.

B. Reliability Metrics

ComEd determined its annual reliability performances using the electric utility industry accepted metrics called SAIFI and CAIDI. ComEd's SAIFI (System Average Interruption Frequency Index) was measured by dividing the total number of customer interruptions (CI) by the total number of customers. ComEd measured its CAIDI (Customer Average Interruption Duration Index) by dividing the total number of customer minutes of interruption (CMI) by the total number of CI.

ComEd addressed SAIFI and CAIDI by applying programs to reduce outage events caused by trees, animals, equipment failures and malfunctions, and other causes, and by employing more circuit sectionalizing and distribution automation, (*i.e.*, self-healing smart grids) to reduce the number of customers affected by each outage and by reducing the duration of each interruption.

ComEd reported its SAIFI and CAIDI reliability metrics in two ways. It reported the metrics including weather (storm) event days and it reported the metrics excluding EIMA defined major extreme weather event days. The reliability metrics with storms excluded provide measures of the effect of equipment condition and the effect of its "blue sky" reliability programs. The metrics including major storm events provide some measure of equipment condition, reliability program effectiveness, as well as the effects of system resiliency programs and projects. Because the impacts of storms depend on storm intensity and spread, comparing different extreme storm events to evaluate the effect of these programs on reducing storm-caused interruptions becomes subjective.

C. Reliability Metric Performance Trends

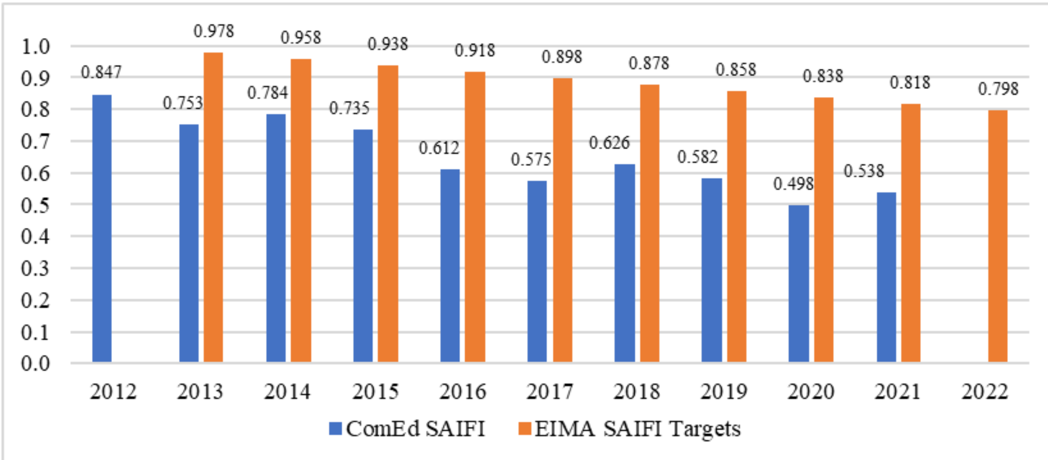
1. Metrics Using EIMA Weather Exclusions and Targets

EIMA allowed ComEd, beginning in 2012, was to exclude up to nine extreme weather event days (EWED) each year when calculating performance metrics. An EWED comprises a 24-hour calendar day during which any weather event has caused interruptions of electric delivery service to 10,000 or more its customers for three or more hours. EIMA included annual EWED-excluded SAIFI and CAIDI targets for each year from 2013 through 2022.

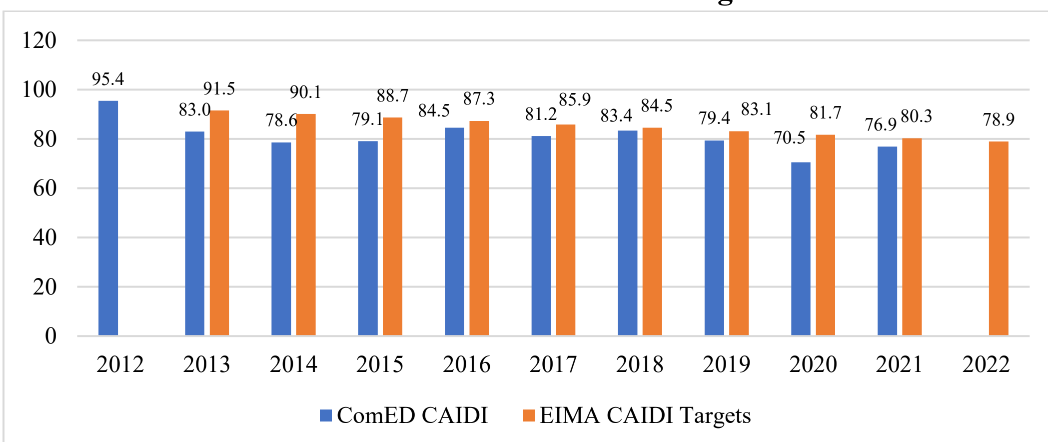
As indicated by the next two charts, ComEd's EWED SAIFI and CAIDI metrics bettered the targeted EIMA performance for each study year. ComEd's 2020 EIMA System SAIFI was about 41 percent better than its 2012 EIMA System SAIFI. ComEd's 2020 EIMA System CAIDI was about 26 percent better than its 2012 EIMA System CAIDI. Performance goals past 2022 remain open pending upcoming ICC proceeding 2022 ILCCS 5/16-108.18. ComEd reported the 2021 EIMA SAIFI and CAIDI metrics as preliminary.

These metrics mean that, when excluding EIMA defined storms, each of ComEd's 4+ million customers experienced, on average, one 95-minute interruption every 1.18 years in 2012 and customers experienced one 77-minute interruption every 2 years in 2020. In 2020, 51 percent of ComEd's customers did not experience any interruptions, compared to 39 percent in 2012.

EIMA EWED Excluded Actual and Targeted SAIFI



EIMA EWED Excluded Actual and Targeted CAIDI



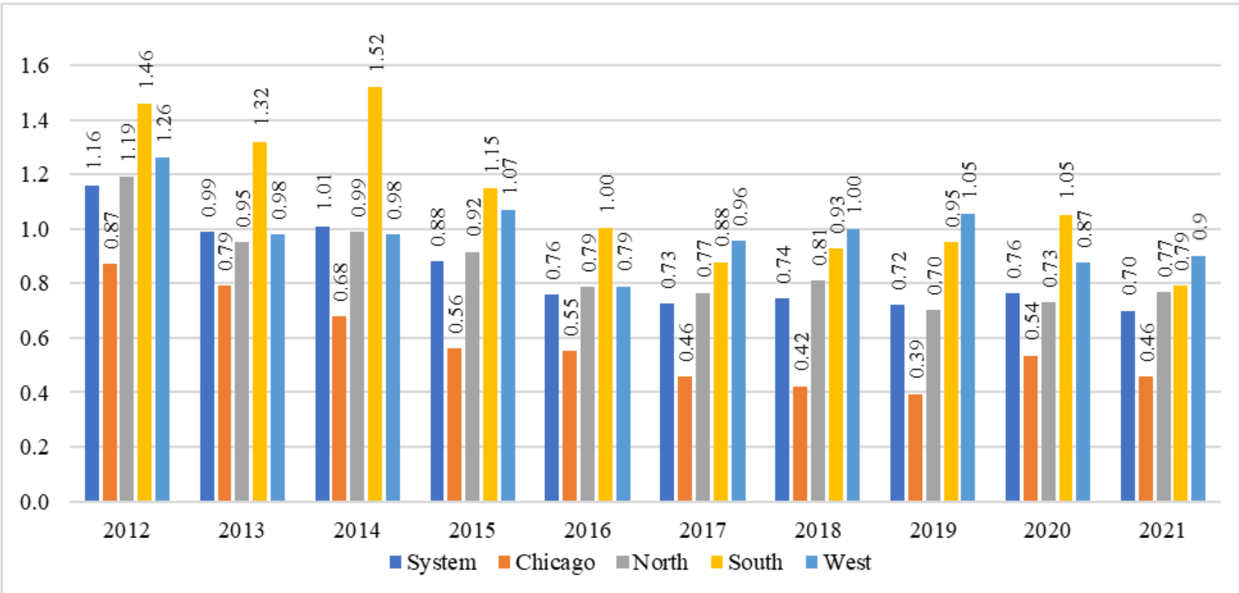
2. *Reliability Metrics*

a. System and Regional SAIFI Including Storms

The following chart depicts ComEd's system and regional SAIFI metrics, including the effects of extreme storms. The Chicago Region shows the best SAIFI, while the more suburban and rural South and West Regions have the worst. ComEd reported that excluding the August derecho the system SAIFI metric for 2020 would have measured 0.57 interruptions per customer, rather than the actual 0.76.

ComEd also reported that the 2020 Chicago Region SAIFI would have been lower, if not for the May 2020 flooding of the Willis (Sears) Tower caused by an extreme amount of rain. SAIFI for the North Region decreased between 2019 and 2020, even including the derecho. ComEd reported the 2021 SAIFI (0.70 interruptions) metric as preliminary.

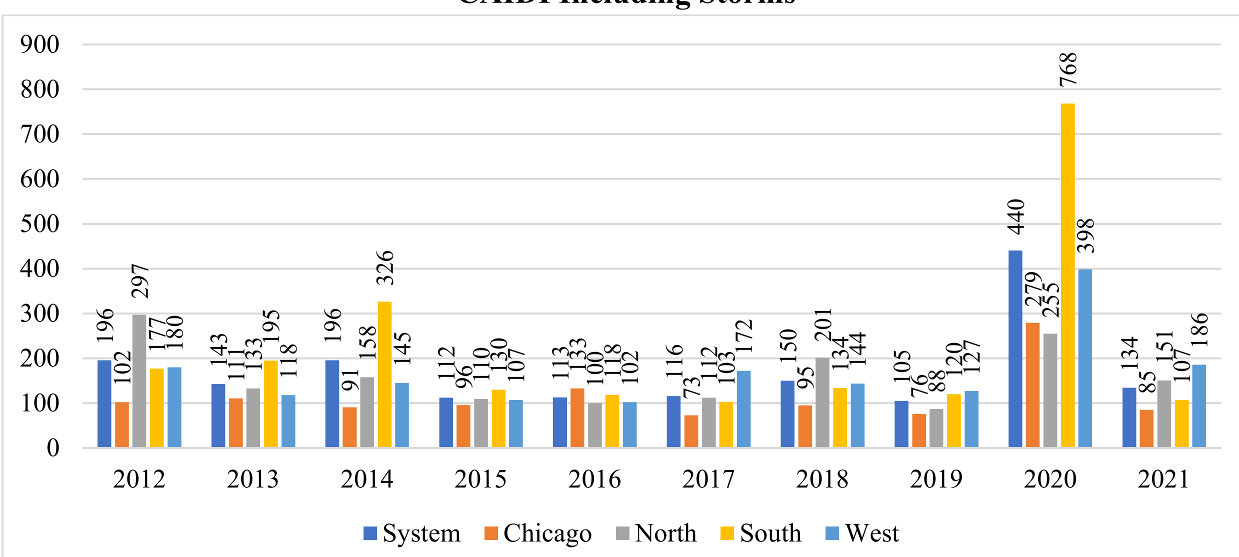
SAIFI Including Storms



b. <u>System and Regional CAIDI Including Storms</u>

As shown below, ComEd's System CAIDI, including storms, improved from 196 minutes in 2012 to 105 minutes in 2019. The August 2020 derecho caused a substantial amount of CAIDI minutes for 2020, especially for the South Region. ComEd estimated that excluding the derecho would produce a 2020 System CAIDI of 96 minutes, rather than the actual 440 minutes. ComEd reported the 2021 CAIDI (134 minutes) metric as preliminary.

CAIDI Including Storms



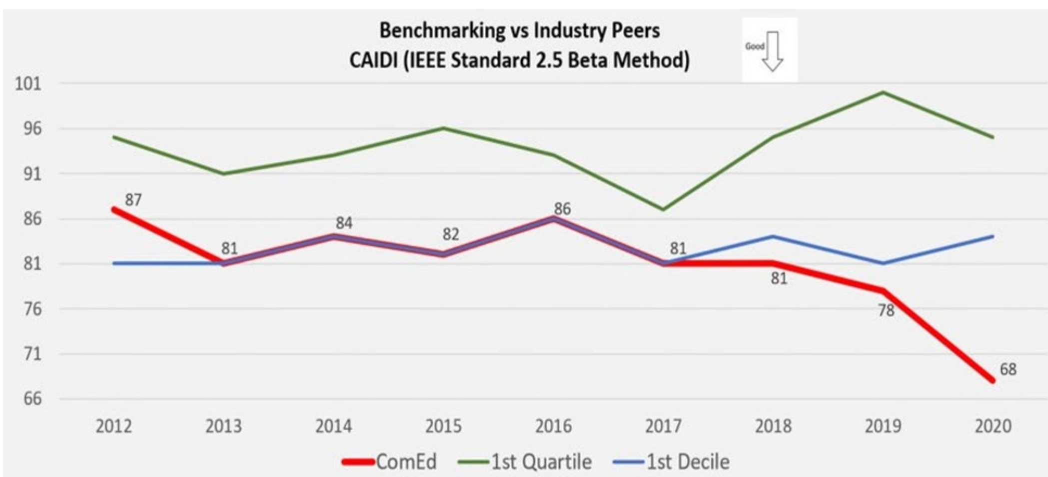
The preceding SAIFI and CAIDI metrics mean that, *when including storm caused outages*, each of ComEd's 4 million plus customers were experiencing, on average, one 196-minute interruption about every ten months in 2012 and customers experienced one 105-minute interruption about every 16 months in 2019. The 2020 CAIDI data was not used for this analysis because of the atypical effect of the 2020 derecho on the CAIDI metric. The 2021 CAIDI metric used preliminary data.

c. ComEd CAIDI Compared with Peer Group

The conditions affecting utility reliability (*e.g.,* system condition, territory size, topography, weather conditions, tree density, customer density, numbers of customers, the amount of rural versus urban areas, circuit tying capability, and the application of distribution automation) differ. Customer reliability expectations and satisfaction also vary around the country. However, comparison of reliability metrics among "most similar" electric utilities remains one way to evaluate ComEd's distribution system performance.

The next chart shows that ComEd's system CAIDI, excluding the Institute of Electrical and Electronics Engineers (IEEE) defined major event days, improved since 2012. Compared with 24 other utilities in ComEd's peer group, its system CAIDI, excluding major event days as defined by the IEEE standard, fell within the IEEE 1st Quartile performance group for the entire period and, for 2017 - 2020, performed in the first decile. Using the IEEE major event day exclusion method resulted in slight deviations from the EIMA extreme storm exclusion method.

CAIDI Performance



3. ComEd CERT Performance

A small number of ComEd's customers experienced multiple interruptions. One justification for the spending approved by EIMA was to reduce the Customers Exceeding Reliability Targets (CERT) metric. The EIMA Act required that ComEd identify and mitigate the causes of excessive interruptions for CERT customers, who are defined by these criteria.

- Customers served at 4kV and 12kV should not experience more than 6 controllable interruptions or more than 18 hours of total controllable interruptions during the last three consecutive years
- Customers served at 34kV should not experience more than 4 controllable interruptions or more than 12 hours of total controllable interruptions during the last three consecutive years

- Customers served at 69kV and 138kV should not experience more than 3 controllable interruptions or more than 9 hours of total controllable interruptions during the last three consecutive years.

The EIMA Act required that ComEd reduce its numbers of CERT customers by 75 percent by the end of the 10-year EIMA commitment beginning in 2013. The Act included annual targets listed in the following table. This table shows that ComEd reported that it had reduced the numbers of CERT customers from over 18,000 in 2012 to 11 in 2018 and 53 in 2019, virtually eliminating them in the Chicago, North, and South regions. However, in 2020 and 2021 high numbers of CERT customers occurred in the South and West Regions causing the numbers of CERT customers to exceed the system targets.

CERT Customers

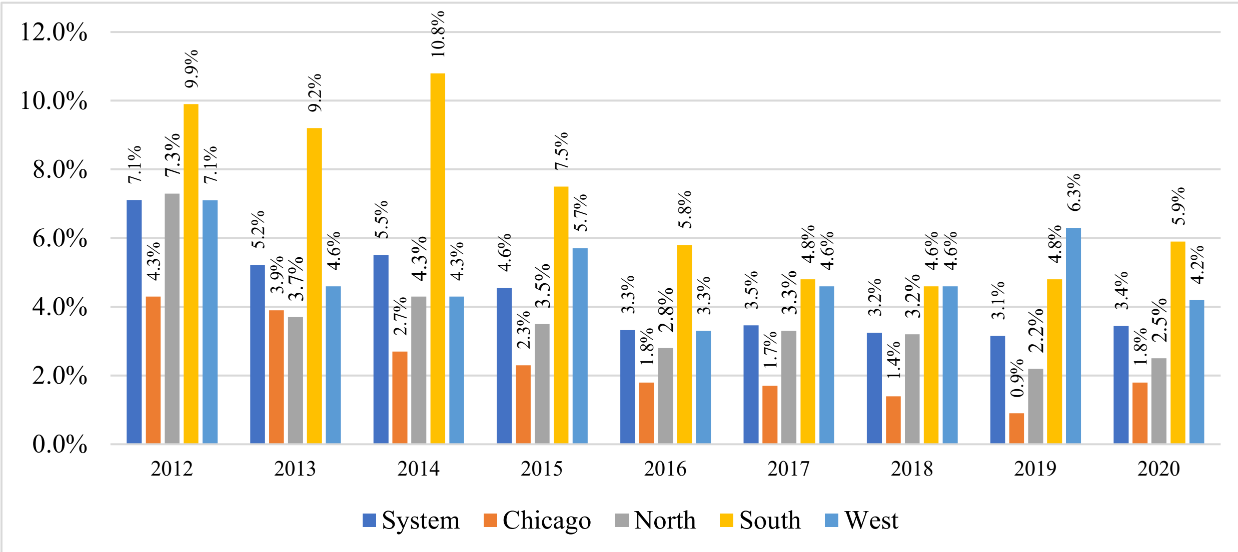
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021*	2022
Target	-	*407*	*376*	*345*	*314*	*283*	*221*	*190*	*159*	*128*	*97*
System	*18,379*	*4,269*	*3,161*	*1,298*	*308*	*14*	*11*	*53*	*649*	636	
Chicago	746	217	83	3	1	0	0	0	0	0	
North	15,008	1,334	26	18	16	0	0	0	2	0	
South	1,073	1,844	2,785	1,108	167	1	2	0	423	55	
West	1,552	874	267	169	124	13	9	53	224	581	

* 2021 counts are preliminary

4. Customers Experiencing More than 3 and 6 Interruptions Each Year

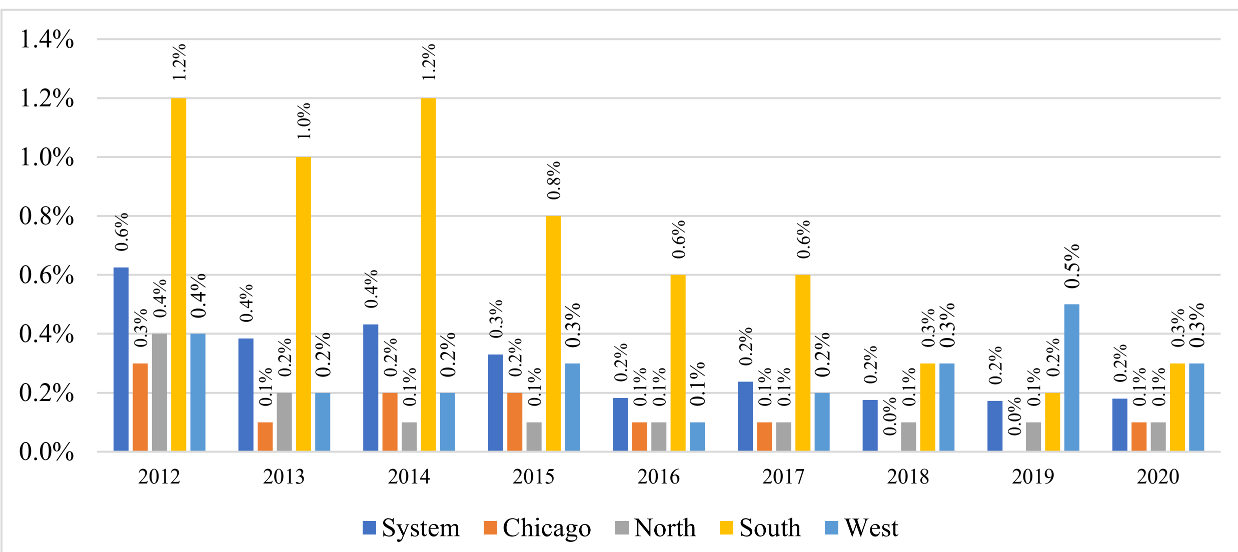
The next two charts provide another indicator of reliability changes over time for the most outage-affected customers, *i.e.,* those experiencing more than three and more than six interruption each year. ComEd reported that it reduced the percentages of its customers experiencing more than three interruptions each year from 7.1 percent in 2012 to 3.4 percent in 2020. The most affected, but most improved, customers were in the South Region.

Percent of Customers Experiencing More Than Three Interruptions



The most improved group comprised customers experiencing more than six interruptions each year. ComEd reduced the percentages of its customers experiencing more than six interruptions each year from 0.6 percent in 2012 to 0.2 percent in 2020. The South Region customers experienced the greatest reduction of six or more interruptions, from 1.2 percent in 2012 to 0.3 percent in 2020.

Percent of Customers Experiencing More Than Six Interruptions



5. *Worst Performing Circuits*

Based on reliability data, ComEd annually selected, inspected, identified the causes of poor performance, and attempted to mitigate those causes for its worst performing circuits (WPC). Reliability engineers selected the one percent worst performing circuits for each region based on worst SAIFI and CAIDI, separately and combined. It tracked and intensified mitigation efforts on those WPCs that repeated during the previous five years.

D. Customer Interruptions and Customer Minutes of Interruption Causes

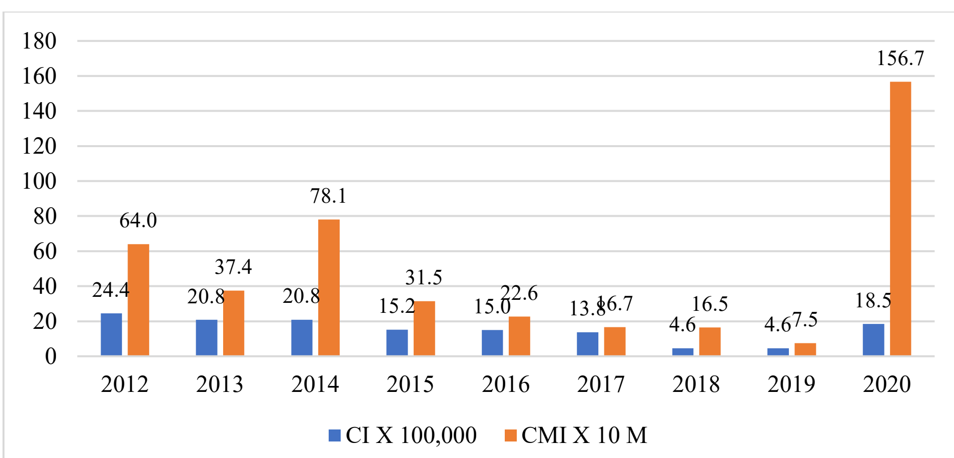
The SAIFI and CAIDI metrics were derived from numbers of customer interruptions (CI) and the customer minutes of interruption (CMI) divided by the total numbers of customers. CMI is the totalization of CI for each outage times the duration in minutes of each outage. CI and CMI provide measures of the overall effect on all customers of ComEd's maintenance, vegetation management, and reliability programs.

This section examines how the combination of ComEd's distribution maintenance and vegetation management programs, its reliability and resiliency initiatives, and its distribution automation application during the study period affected annual CI and CMI assigned to the major outage causes. The following narrative and charts indicate the numbers of CI and CMI each year, and the year-to-year trends, by order of greatest causes of CI and CMI in 2020. The charts are based on CI and CMI data found in ComEd's Electric Power Delivery Reliability Reports, Appendix 2, 2012 through 2020.

1. Weather Related CI and CMI

Data from2020 indicated 1.8 million CI and 1,567 million CMI. During the study period, weather related CI and CMI both reduced by more than three-quarters by 2019. However, the impact of the atypical August 2020 derecho had a substantial effect on the 2020 CMI and making weather the greatest contributor of CI and CMI in 2020. Until 2020, weather CI and CMI metrics were improving or stable. As indicated by the next chart suggests. ComEd's efforts during the study period to improve storm resiliency and to reduce lightning caused outages were effective. ComEd improved its lightning detection methods and increased replacement of lightning arresters.

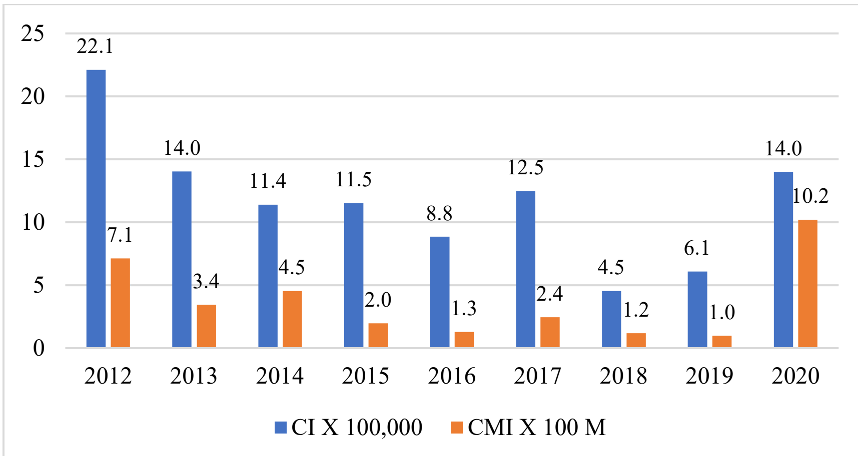
Weather-Related CI & CMI



2. Tree Related CI and CMI

Data from 2020 indicated 1.4 million CI and 1,000 million CMI. Over the study period, other than 2020, tree-related causes were the greatest contributor to CI and CMI. However, during the study period, including 2020, tree-related CI dropped by about one-third but CMI increased by more than 43 percent. As described in Chapter VI: *Distribution System Condition*, these programs included enhanced tree trimming, hazard tree removals, and - where trimming was not effective -- by undergrounding specific segments or by installing tree resistant overhead spacer cable. ComEd's System Hardening program included replacing about 400 miles of tree exposed overhead lines, and by installing about 510 miles of overhead tree resistant spacer cable.

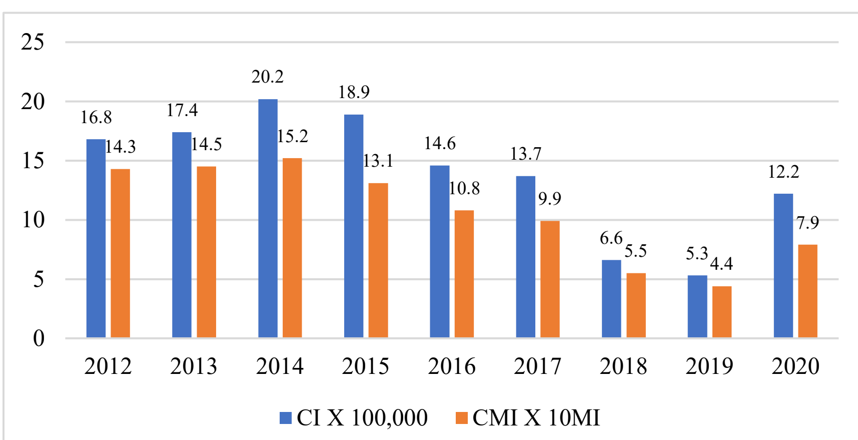
Tree-Related CI & CMI



3. *Overhead Equipment Caused CI and CMI*

Data from2020 indicated 1.2 million CI and 79 million CMI. During the study period, overhead equipment-related customer interruptions (CI), including the effects of the 2020 derecho, dropped by one-quarter, and the customer minutes of interruption (CMI) dropped by 45 percent. The improving trend of these CI and CMI metrics as indicated by the next chart suggests that the condition of ComEd's overhead distribution equipment, along with improved distribution automation, was sufficient to reduce overhead equipment related CI and CMI.

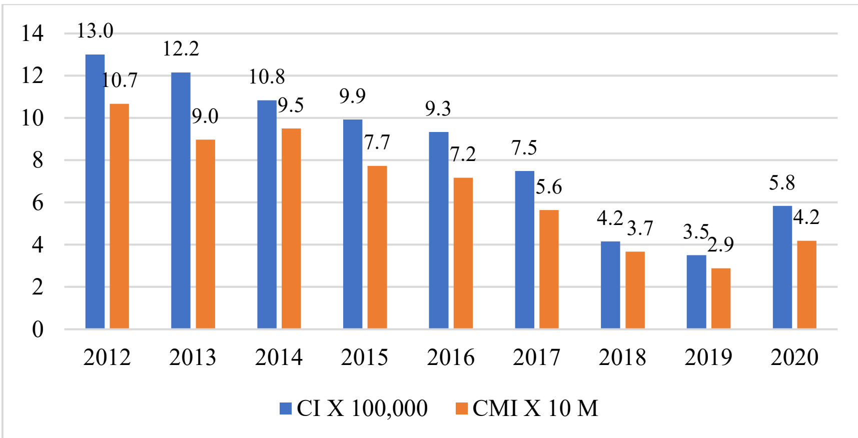
Overhead Equipment-Related CI & CMI



4. Underground Equipment Caused CI and CMI

Data from 2020 operations indicated 583 thousand CI and 42 million CMI. Underground cables made up nearly one-half of the distribution circuit mileage, indicating EIMA cable replacement program work effective, given the more than 55 percent reduction in underground related CI and the 61 percent reduction in CMI over the study period, including the effects of the 2020 derecho storm.

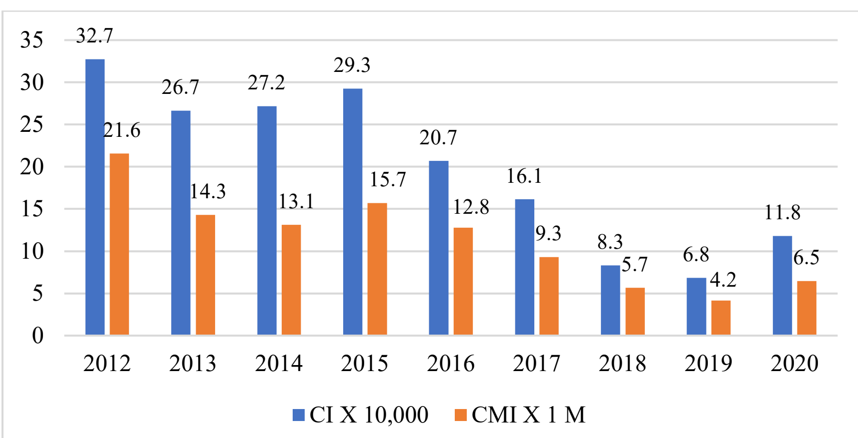
Underground-Related CI & CMI



5. Animal Related Caused CI and CMI

Data from 2020 operations indicated 118 thousand CI and 6.5 million CMI in 2020. Although not among the greatest contributors, animal contact-related CI dropped by 64 percent and CMI by 70 percent. The improving to stable trend of these CI and CMI metrics indicated by the next chart suggests that ComEd's measures to reduce avian and ground animal contact with power lines and substation equipment have been effective**.**

Animal-Caused CI & CMI



6. CI and CMI Attributable to Unknown and Other Causes

During the study period, the CI and CMI attributable to Unknown and Other causes decreased by one-half or more. The ability to assign more values to specific causes has improved management's ability to address reliability issues. CI and CMI resulting from "errors" made by ComEd or by contractors fell by roughly three-quarters.

The contribution of other causes of interruptions changed as follows:

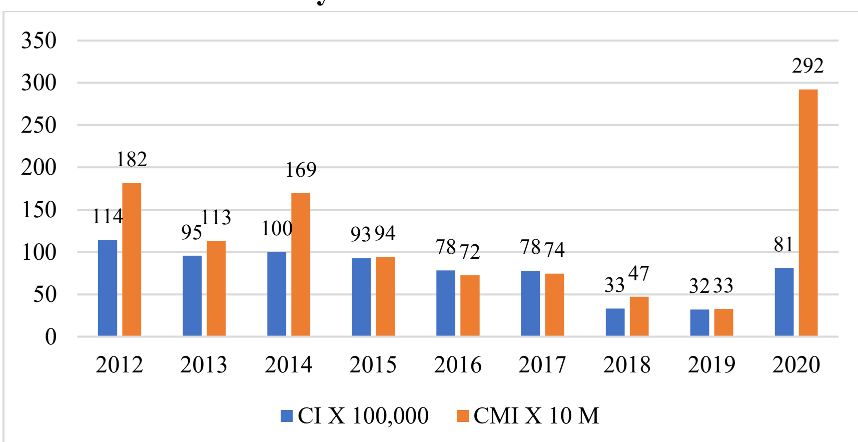
- Customer caused (*e.g.*, car-pole accidents and vandalism) or requested outages: CI increased 93 percent and CMI increased 191 percent
- Intentional Scheduled Construction, Maintenance or Repair: CI increased 110 percent increase and CMI increased 100 percent
- Public: CI increased 19 percent and CMI decreased 11 percent.

E. System CI and CMI and By Region

1. System CI and CMI

During the study period the annual CI and CMI metrics followed the same declining trend, except for 2020, as did the storm-included SAIFI and CAIDI.

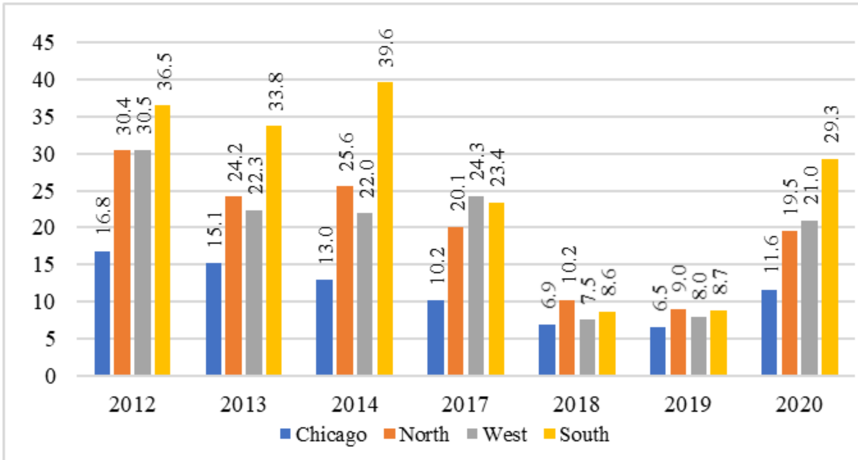
System CI and CMI



2. Regional CI and CMI

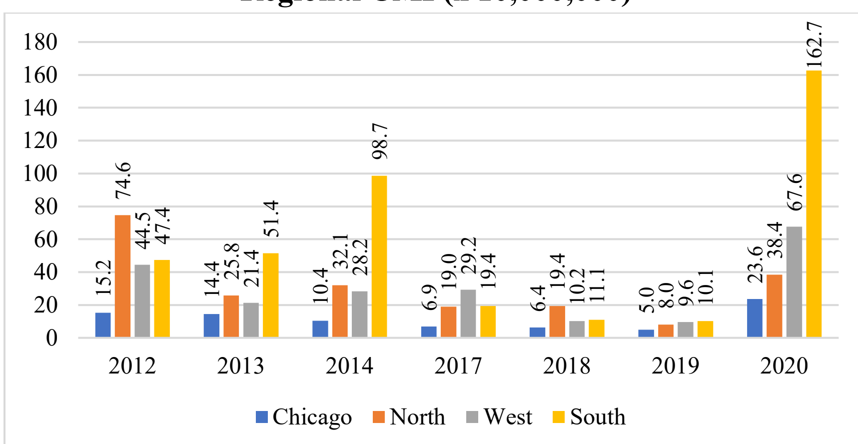
The numbers of customer interruptions (CI) for the Regions outside of Chicago were about double of those experienced by customers in the Chicago Region, except in 2018 and 2019 when customers in all Regions experienced low numbers of CIs.

Regional CI (x 100,000)



This chart suggests that the duration of interruptions in the South Region may be the most affected by storms.

Regional CMI (x 10,000,000)



These charts exclude 2015 and 2016 data as Annual Reliability Reports did not contain regional CI and CMI information.

F. Transmission and Substation Caused CI and CMI

We determined that ComEd's transmission system and substations outages contributed less than five percent of the annual CIs and slightly more than one percent of the CMIs during the study period. The transmission system and substation equipment condition, configuration redundancies, and automation capabilities are all reflected by the CI and CMI contributions. A transmission system or substation outage, although relatively rare, can cause numerous CI and CMI. However, when viewed as percentages of total system CI and CMI, the transmission system outages and the substation outages contributed only small percentages compared with the distribution system outages. The percentage contribution to total CI and CMI by the transmission system, by substations, and by the distribution system did not change appreciably from year-to-year during the study period. Percentage contributions to total CI in 2021 (which were representative of all study years) including major event days, was 1.6 percent for transmission, 2.9 percent for substations, and 95.5 percent for the distribution system. Corresponding CMI contributions by the transmission system, substations, and the distribution system were 0.2 percent for transmission, 0.9 percent for substations, and 98.9 percent for the distribution system. The only identifiable change consisted of a trend of reduced percent contribution from substations between 2012 and 2021.

G. Reliability and Resiliency Prioritization and Metric Improvement

1. System Performance and Reliability Improvement Policies

ComEd stated that "[t]he System performance core function assesses the performance of the delivery system through standard and objective performance metrics that are recognized industry wide. The function ensures the system is evaluated and managed to mitigate adverse material condition and system performance issues on an ongoing basis. System Performance ensures that programs are written and followed to improve equipment and system reliability, operability, and preservation while utilizing efficient application of resources."

ComEd reported that it identified and prioritized its electric system performance programs and their funding either based: (a) on programs' abilities to drive reliability improvement for its ageing system, for individual customers experiencing excessive interruptions or durations, for the worst performing circuit program, or (b) for meeting safety and regulatory requirements, while maximizing reliability returns on investments. The System Performance organization uses system reliability assessment and reporting processes intended to provide senior management and the ICC with the required performance metrics and programs' progress.

ComEd's reliability programs targeted both system performance and "pocket" reliability (described in more detail in Section H). System performance engineers improve performance through modifications to the system design and through the application of new technologies and equipment to prevent outages and to reduce the impact of outages on customers. Pocket reliability programs targeted poor performing sections of circuits not specifically targeted by broader system performance programs. Other programs included mitigating lightning, vegetation, wildlife caused outages and by applying cable replacement and distribution automation.

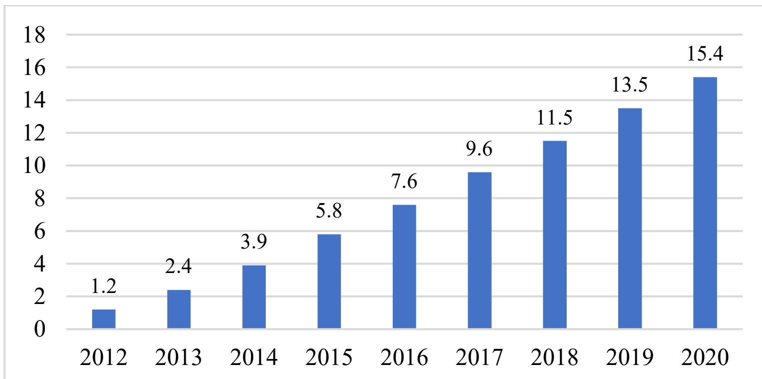
2. Prioritizing Reliability Programs

Other than for CERT and Worst Performing Circuits (WPC) programs, ComEd selected its reliability improvement programs based on comparing cost with expected reliability benefits. It weighed the costs of programs against the ability to avoid customer interruptions (CI), customer minutes of interruption (CMI), and outage frequencies and durations. Engineers estimated benefits based on dollar per avoided CIs and CMIs over a ten-year period. It limited the application of a program where the program did not provide the required minimum cost benefit.

3. Measuring EIMA and Baseline Reliability Program Benefits

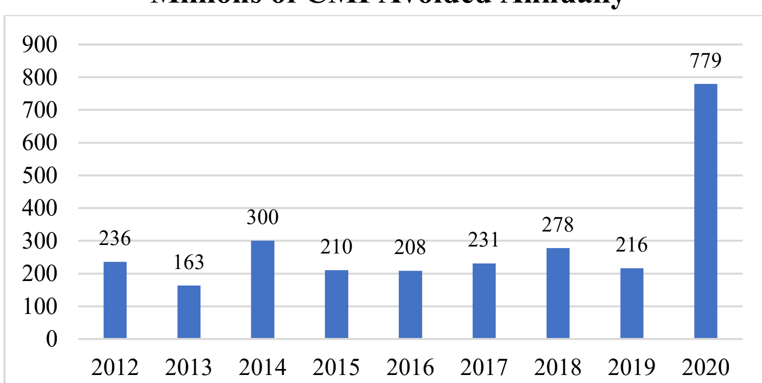
ComEd reported that it scoped reliability programs, other than those addressing low reliability pockets, using CI and CMI benefit to cost ratios. ComEd measured post-completion benefits of EIMA funded and non-EIMA funded reliability and resiliency programs by identifying the apparent resulting numbers of avoided CI and the numbers of avoided CMI. It developed estimates each year for avoided CI and CMI post-completion of the reliability and resiliency programs. ComEd estimated avoided CI and CMI based on CI and CMI history and the impact of the distribution automation and other reliability and resiliency actions undertaken. The following chart shows the total accumulated millions of CI estimated to have been avoided by ComEd's reliability programs, including EIMA reliability programs, implemented during the study period. Based on engineering analyses following outage events, ComEd estimated that, since 2012, the cumulative reliability programs such as distribution automation, including the EIMA programs, avoided (prevented) over 15 million CI, at a rate of about two million more CI each year, and avoided more than 200 million CMI each year until 2020, the year of the derecho, when 779 million CMI were avoided.

Accumulated Millions of CI Avoided



This next chart reflects the millions of customer minutes of interruption estimated to have been avoided each year by the implementation of the ComEd's reliability programs, including EIMA reliability programs. The 2020 increase in avoided CMI was due to the CMI avoided during the 2020 derecho.

Millions of CMI Avoided Annually



H. Reliability and Resiliency Improvement Initiatives

1. Pocket Reliability and Targeted Resiliency Practices

ComEd reported that it proactively targeted overhead situations requiring resilience improvements, and reactively targeted "pockets," circuit segments requiring reliability improvements, based on a scoring method for prioritizing the mitigation work. Pocket reliability mitigation included replacing poor performing overhead conductor or underground cable, installing, or relocating mainline and lateral tap reclosing devices, addressing tree issues, installing fiberglass cross arms, and replacing overhead open wire with tree-resistant spacer cable. Examples of proactive targeted resilience activities included those under pocket reliability, including undergrounding circuit segments, installing spacer cable, installing new underground tie circuits to other circuits, and installing loops around a poor performing circuit segment.

ComEd reported that, during the study period, in addition to the increased distribution automation, it installed over 700 miles of overhead spacer cable, 6,500 miles of new wire for new installations and for system reliability work, and almost 1,400 automatic 1 phase and 3 phase reclosing devices for protecting lateral taps. ComEd had replaced 3-phase reclosing devices with three 1-phase devices, where applicable, to reduce customer interruptions related to faults involving only one phase of a circuit.

2. CAIDI Improvement Initiatives

CAIDI metrics reflect the average time between interruption and restoration of service, including time for arrival of first responders and repair crews, and the actions required to restore service. ComEd reported that, since 2012, it implemented several process improvement initiatives to reduce the time to restore service.

- For URD outages, first responders start the troubleshooting process at the midpoint of larger URD loops rather than working from the source
- Repair crews can employ rapid overhead deployment trailers equipped to suspend downed wires while poles are repaired/replaced; generators are provided and temporary cable runs are employed, and other equipment designed to allow restoration of service to customers while permanent repairs are being made
- Office and regional boundaries are ignored if that expedites outage response
- Office staffing is based on quarterly analysis of CAIDI and customer interruptions
- Parallel dispatching processes are conducted with line supervisors and managers to coordinate and support large customer outages.

ComEd reported that it implemented during the study period several processes and technologies to help manage and oversee outages involving more than 100 customers including:

- Sending parallel dispatch emails to regional leadership to provide real-time visibility for overseeing and assisting in addressing barriers to speedy restorations
- Monitoring the Operation Control Center Dashboard to track high-impact CAIDI outages
- Using internal communication to conduct daily meetings related to current outages to understand specific CAIDI drivers and to prioritize returning switched circuits to normal configuration.
- Using software tools to identify CAIDI trends promptly
- Using its new advanced meter infrastructure (AMI) Smart Meters to identify meters energized and de-energized, thereby avoiding crew needs to radio in restoration progress. AMI allows dispatchers to identify stranded de-energized customer meters that might otherwise miss restoration activity.

3. Grid Analysis Tools

ComEd reported it implemented during the study period distribution design, operations, and automatic sectionalizing and restoration features that enhance system condition, reliability, and resiliency under both normal and extreme storm weather conditions. Reported various grid analysis processes, equipment, and schemes to improve reliability, since 2012 ComEd include:

- Improved reliability reporting and analytical tools, including spatial analysis to identify potential reliability issues and increase visibility to those customers with multiple interruptions. Customers experiencing multiple interruptions have decreased by over 70 percent since 2012.
- In 2018 ComEd developed an algorithm using AMI (Advanced Metering Infrastructure) generated data to predict distribution service transformer failures and, since 2019, uses AMI generated data to validate and automatically correct customer outage data.
- Development of the ability to remotely set its distribution automation devices to "fuse clearing," allowing downstream lateral fuses to clear faults during normal conditions, or to "fuse-save" causing reclosers to operate before a fuse blows. Fuse save mode prevents temporary faults from causing sustained outages. ComEd uses the fuse save mode during storms.
- Installation of automatic circuit reclosers, called smart switches (within distribution automation smart grid schemes) on distribution circuits to isolate circuit faults and reroute power for remaining unfaulted circuit segments. ComEd has the goal to increase the numbers of reclosers and smart grids such that only 450 to 750 customers at most are interrupted by an outage, ComEd reported the maximum number of customers in a circuit segment protected by a recloser currently at approximately 1,500.
- In 2016 ComEd developed an analytical tool for determining optimal distribution automation segmentation solutions for each circuit based on historical feeder lockout data, overhead and underground circuit exposure, and the cost per avoided customer interruption.
- In 2018 ComEd implemented an algorithm tool that correlated lightning strikes with momentary interruptions using the location and intensity data from its lightning service used since 2002. Since 2018, ComEd found that its first responders have doubled the rate of finding lightning-caused damage with the use of the tool.
- In 2020 ComEd created an analytical model and process that scans the distribution system for protective device and fuse mis-coordination issues. In 2021, ComEd created an interactive map to indicate coordination issues. ComEd reported that it has since then identified and corrected coordination issues at three times the previous rate.

4. Powerline Design Improvements and Construction Standardization

ComEd reported that it improved its distribution powerlines design methods and its construction methods to ensure best designs and standardized construction methods, including:

- In 2015 it adopted the use of powerline design software that automatically and more efficiently (with fewer manual calculations) calculates physical forces on structures to ensure that designs meet requirements.

- In 2018 it began using laser and GPS technology to best model design applications, using the powerline design software. ComEd reported that the modified distribution line construction methods improved installation efficiency, standardization, safety, and quality control.
- Starting in 2008, and enhanced in 2020, ComEd preassembled standardized equipment packages for construction crews.

5. Improved Automatic Sectionalizing and Restoration

ComEd reported that it advanced its distribution automation (DA) capability to improve sectionalizing and restoration - reducing the numbers of customers affected by an outage. ComEd began using in 2020 high bandwidth and high-speed communications to improve protective device timings, to minimize fault durations, to minimize voltage sag impacts, to minimize damaging fault energy on the system, and to minimize the numbers of customers and equipment exposed to momentary interruptions. ComEd implemented single-phase rather than three-phase reclosers where it can improve reliability for customers on unaffected circuit phases. It also implemented relay settings that detect and mitigate conditions causing upstream conductors to "slap" (when overhead wires are forced together by the electromagnetic forces from high current downstream fault). Since 2016, ComEd has been installing line sensors that allow system operators monitor load conditions on sections of underground and overhead circuits.

The distribution automation (DA) equipment includes automatic circuit reclosers and self-healing smart grid schemes. ComEd increased the numbers of automatic circuit reclosers from 3,062 in 2012 to 7,444 in 2020. It increased the numbers of "self-healing" smart grid schemes from 733 in 2012 to 1,990 in 2020. Smart grid schemes automatically detect and isolate faults, use a smart algorithm to determine whether a second circuit can accept load, and transfers loads downstream from the faulted circuit segment to another circuit. Smart grid schemes often offer an effective method of reducing SAIFI and CAIDI.

6. Reduced Animal Caused Outages

ComEd reduced animal-related CI and CMI by two-thirds and reported that it had installed and is installing additional and more effective animal protection. In 2014, ComEd increased clearances between its 34kV lines to better protect avian caused outages and in 2018 it began installing new wildlife products to provide a barrier to animals climbing wood poles and reaching energized conductors and equipment.

7. 34kV Dist. Circuit Automatic and SCADA Controlled Sectionalizing

ComEd reported that in 2016 it began requiring new 34kV circuit equipment, and updating its legacy 34kV circuit equipment, to a standard design that allows the use of additional SCADA and automatic sectionalizing equipment.

8. Improved Access in Residential Areas

ComEd reported that since 2014 it has been installing primary service (4/12/34kV) to residential areas on street side locations rather than back lot locations, as practical, to permit easier access, which reduces CAIDI. Also, where underground equipment accessibility might be limited or encumbered, ComEd has been installing URD cables in conduit, rather than directly burying the cables preventing the need to dig, which reduces public safety hazards.

9. Substations - Deploying Communication Technologies

ComEd reported that it has deployed and continues to deploy to applicable substations new communications technologies and fiber optics, along with upgraded programmable protective relays, SCADA, and intelligence schemes within substations to better monitor alarms and to reduce substation distribution bus fault clearing times. These schemes allow dispatchers better awareness of alarms and reduce bus fault clearing times, reduce possible bus and equipment damage, and improve reliability. ComEd installed automatic circuit fault location systems at 27 of its substations serving the 12kV system. The systems automatically report fault type and approximate location via emails to dispatchers and reliability engineers. This system reduces time required by first responders to locate circuit faults, which reduces CAIDI. Automated fault location schemes are not effective on the 34kV network system; ComEd depends there on oscillography records provided by microprocessor relays for providing 34kV fault data. Before 2018 these records required manual download at the relays. Since then, these oscillograph records transfer automatically to a computer drive accessible remotely by engineers for analysis, saving considerable time for the engineers to analyze each 34kV fault and the time required for first responders to restore service. ComEd has installed dissolved gas analyzers (DGA) on its 40 MVA and larger transformers to monitor the internal condition. Dispatchers monitor transformer gas levels alarms via the SCADA system.

I. System Hardening Initiatives

1. Storm Hardening Benefits

Evaluating improvements resulting from ComEd's storm hardening and resiliency programs during the study period is somewhat subjective, since storm intensity and territory coverage are varied for each storm. However, until the August 2020 derecho storm, annual weather-related CI and CMI reduced by more than 75 percent.
Regarding the 2020 derecho caused CI and CMI, ComEd explained in its 2020 Electric Power Delivery Reliability Report that "On August 10, 2020, ComEd experienced a derecho that resulted in the second largest customer interruption event in history, impacting approximately 800,000 customers. The system improvements made since the July 2011 [extreme storm] event was responsible for avoiding almost twice the customer interruptions allowing for the restoration of 49 percent of customers in 12 hours, 67 percent in 24 hours, 85 percent in 48 hours, 93 percent in 72 hours, with the final customer restored on August 16.

2. Increasing Strength of Distribution System Components

ComEd historically limited installation of National Electrical Safety Code (NESC) Grade B (more robust) construction for its wood distribution poles only where required, such as at limited access highways and other critical crossings. Otherwise, it installed Grade C wood poles (less robust).

To better withstand major weather events, ComEd reported that it began in 2014 to require that all new wood distribution poles installed meet the Grade B construction standard (larger diameter and stronger) across the system. Grade B poles have 50 to 100 percent greater strength than do Grade C poles. In 2019 and 2020, ComEd began upgrading legacy distribution mainline circuits (from substation to end of circuit, not including lateral taps) to Grade B construction when modified and for future new feeder designs.

Also, ComEd reported that since 2015 it installed fiberglass dead-end cross arms (stronger than the legacy wood cross arms), and installed polymer equipment insulators, (more resistant to surface electric tracking and to breakage than porcelain insulators).

3. Substation Resiliency Initiative

a. <u>Flood Walls Initiative</u>

ComEd implemented in 2016 a substation flood mitigation program to improve substation resiliency to flooding events. ComEd reported that it assessed 840 substations for flood risk and criticality and installed flood walls, water lift stations, and river level monitors, starting with substations with the highest potential of flooding. Additionally, ComEd secured for substations with flood risk, flood forecasting technologies that allow management to pre-deploy sandbags and pumps.

b. <u>Staging Spare Large Transformers Initiative</u>

During the study period, ComEd purchased and staged spare large transformers in secure locations to ensure availability of long lead time large power transformers in case a transformer is destroyed by vandal or terrorist attacks, or other unexpected events.

c. <u>SAIFI Mitigation Initiative</u>

ComEd reported that it completed a transmission and substation SAIFI recovery plan in 2018 that included 24 initiatives such as wildlife fencing, circuit breaker overhauls, and bus inspections. It reported that the mitigations avoided about 20,000 customer interruptions (CI) by the end of 2018, and it continued to reduce CI during subsequent years.

4. Chicago's Bronzeville Area Microgrid Initiative

ComEd began deploying in 2018 the first utility-operated microgrid cluster, the Bronzeville Community Microgrid (BCM), for the purpose of demonstrating how microgrids, using clean energy DER power sources along with battery storage systems, can provide resilience during disruptive events. ComEd developed programs to promote an understanding of how of microgrids operate, especially during extreme conditions, including a proprietary microgrid value software for determining the appropriate sizing of DER sources for microgrids. It installed advanced sensors within the microgrid to provide it with situational awareness of the changing generation and loads, and for supporting existing and future technologies. Partnering with Lawrence Berkeley National Laboratory, ComEd began development of a tool to evaluate the economic impact of disruptive events and how the microgrids like the BCM provide resiliency benefits during disruptive events.

J. EIMA Reliability & Resiliency Programs & Impacts

In addition to its distribution automation reliability program, ComEd reported that it implemented during the study period new resiliency programs aimed at:

- Making the substations smarter (*e.g.*, fault locating relays and electronic communication with circuit protective devices)

- Increasing substation flood prevention
- Improving lateral tap circuit protection
- Installing stronger poles and cross arms
- Clearing overhead limbs, removing hazard trees
- Improving lateral tap circuit protection, where optimal, to mitigate localized pocket CERT and WPC tree-related issues, replacing tree-exposed overhead open wires with either underground cable or with overhead spacer cable.

1. Underground Residential Cable Injection and Replacement Program

This $545 million Underground Residential Distribution (URD) Cable Injection and Replacement program that ComEd conducted from 2012 through 2017 contributed to the reduction of URD cable-caused outages from 6,424 in 2012 to 2,799 in 2020. Fewer URD cable-caused outages resulted in improved SAIFI and CAIDI performance metrics, and a reduction in customers experiencing multiple interruptions, as well as reducing the need for resources and truck roll outs to repair URD cable failures.

URD cables were historically direct buried to serve primary loops for residential and commercial customers. The cables installed in the 1960s through the 1980s employed insulation susceptible to water contamination, resulting in electrical failure. Their exposed bare concentric neutral conductors in many cases corroded and dissolved causing possible hazardous stray currents in the earth. The legacy practice consisted of replacing failed URD cable sections after two or three failures in two years. This practice produced URD loop outages causing multiple customer interruptions and numerous truck rolls.

The EIMA Infrastructure Investment Plan (IIP) URD program reduced future URD caused outages and prevented stray ground currents. ComEd installed about 8,700 miles of the old concentric neutral polyethylene insulated cable between 1966 and 1985. Between 2012 and 2017, ComEd addressed failures of old URD cable failures by injecting an insulating sealant into cables to prevent future cable failures when practical. When injection was not practical, ComEd replaced old URD cables with modern ethylene propylene rubber insulated cables (not affected by water contamination) which had jacketed neutral conductors. ComEd injected 412 miles of URD cable between 2011 and 2016 and replaced 3,478 miles of URD cable between 2011 and 2017. The company scheduled injection and replacement work to prioritize the worst performing URD cable.

2. Mainline Cable Replacement Program

This $392 million program from 2012 through 2017 reduced mainline cable-caused outages from 694 in 2012 to 381 in 2020 and improved conditions in manholes. Reduced number of mainline cable-caused outages resulted in improved CAIDI and SAIFI measures and lessened required numbers of personnel needed to repair mainline cable, vaults, manholes, and cable support systems. This program also improved safety working in manholes.

This program included assessments of 34,712 manholes for vault conditions, cable support issues, and cable termination and joint issues. ComEd conducted IEEE Very Low Frequency (VLF) cable tests (to determine failure risk) on 932 sections of mainline cables. Based on inspections and cable testing, ComEd replaced 683 miles of the mainline cables. ComEd's mainline underground system consists of about 8,300 miles of cable, much of it consisting of aged lead jacketed oil filled paper insulated lead covered (PILC) cable with some dating to the 1930s and earlier. This program included assessments of cables, manholes, and cable support systems. The PILC cables include oil filled joints (splices) and terminations, which can experience bulging and oil leaks that lead to failures, often in enclosed manholes.

3. *Ridgeland 69kV Cable Replacement Program*

This $31 million program from 2012 through 2015 continued a program begun in 1998 to replace sections of the aged 69kV Ridgeland cable. The 69kV system serves many distribution substations. Fewer 69kV cable-caused outages results in reduced CAIDI and SAIFI and reduced resources and truck roll outs to repair aged cable.

Some of the 40.5 circuit miles of cable in the Ridgeland 69kV system used paper insulation, installed from 1927 to the 1950s. The 2012 to 2015 program consisted of replacing 10.2 miles of old cable with modern cable.

4. *Construction of Training Facilities*

Reliable field work requires trained, skilled workers. During 2012 through 2015, under the EIMA Program, ComEd funded $10 million for construction of the new Chicago training facility and the new Rockford training facility. EIMA funding earmarked $2.7 million for the Chicago facility upgrade and $7.3 million for the Rockford facility.

The Chicago and Rockford training facilities expanded ComEd's ability to provide training to new and experienced line and substation employees. The facilities included poles, URD, manholes, conduit, substation training facilities, and rooms for community outreach initiatives.

5. *Wood Pole Inspection, Treatment, and Replacement Program*

This $81 million capital program from 2012 through 2016 accelerated ComEd's legacy program of inspecting, chemically treating, and replacing or reinforcing decayed wood poles. ComEd inspected and treated 737,344 wood poles between 2012 and 2016 and replaced or reinforced 20,548 wood poles.

6. *Storm Hardening Program*

This $202 million capital program from 2012 through 2017 reduced tree caused outages and included enhanced tree trimming, installations of tree resistant overhead spacer cable, and the installation of underground cable to bypass tree issues. Program work prioritization considered each mainline circuit's historic susceptibility to storm damage and where work could provide the greatest expected reliability benefits.

7. *Distribution Automation (DA) Program*

This $242 million capital program from 2012 through 2016 included the installation of 2,609 new devices for distribution automation schemes, including self-healing smart grid schemes that automatically isolate faulted circuit sections and automatically restore unfaulted circuit segments. This program also included replacement of the legacy DA device communication systems with more effective and more cyber secure communications systems. It also included software upgrades of the 34kV system protection software that provided better 34kV system protection communication and fault isolation.

8. Substation Micro-Processor Relay Upgrades Program

This $134 million capital program from 2012 through 2020 produced modernization of 14 substations by upgrading protective relays, improving security, adding dynamic voltage regulation, replacing aged circuit breakers, adding SCADA communications, and adding devices to monitor transformer health.

9. Implementation of Advanced Metering Infrastructure

See Chapter VIII, *Advanced Metering Infrastructure*, for program descriptions and costs.

VIII. Advanced Metering Infrastructure

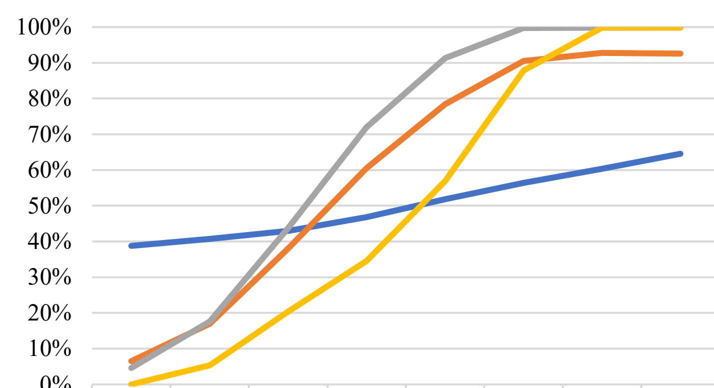
A. Summary

Advanced Metering Infrastructure (AMI), consisting of advanced or "smart" meters linked together through communication networks and supported by data management systems, is a key element of grid modernization. AMI facilitates more timely access to customer usage data through the availability of more granular data, often collected hourly or in shorter intervals through a two-way communications link between customer and utility. This digital linkage, providing key operational data for the utility, can also serve as a channel to offer new and expanded services such as home energy management, load control, time-varying energy pricing, outage notification, and usage alerts.

The primary benefits of AMI to a modernized grid include reliability and resilience, both improved because of quicker identification of electric system faults, enabling more rapid dispatch of company resources to repair the faults, or even the potential avoidance of dispatching resources by restoring service through distribution system automation and control. Secondary benefits include better access to customer usage data, reduced field trips to collect usage data or turn service on or off, more timely and more accurate usage billing, support for DER initiatives, communication with and control of smart devices, volt-VAR optimization, and better information and rate options for customers to control their energy usage.

At the end of 2020, more than 5.6 million AMI meters have been deployed in Illinois (93 percent of total meters) -- 4.2 million at ComEd and 1.2 million at AIC. AMI deployment within the State of Illinois has outpaced national AMI growth since 2016 as the next chart illustrates -- largely a result of the 2011 EIMA requiring participating electric utilities in Illinois to invest in Smart Grid upgrades in the State's distribution network over a ten-year period.

AMI Meter Growth – Illinois vs U.S.



	2013	2014	2015	2016	2017	2018	2019	2020
U.S.	39%	41%	43%	47%	52%	56%	60%	65%
Illinois	7%	17%	38%	60%	78%	90%	93%	93%
ComEd	5%	18%	44%	72%	91%	100%	100%	100%
Ameren	0%	5%	20%	35%	57%	88%	100%	100%

EIMA intended to improve overall distribution system performance through accelerated investment in programs that address aging infrastructure, storm hardening, and expanded smart grid technologies. EIMA encouraged investment and set up an annual performance-based rate process to review utility investment and performance to determine cost prudence and reasonableness. Penalties could apply for underperforming metrics (described in Section D.3) and rates would be approved, based on the investment, for the following year. ComEd satisfied its EIMA AMI-related performance goals each year during the deployment without incurring any penalties.

EIMA provided ComEd with pre-approved AMI-targeted capital expenditures of $905 million, with the company projecting 100 percent AMI deployment by 2018. By year-end 2018 ComEd had achieved 100 percent AMI meter deployment (excluding non-standard metering customers and access issues). Program costs at the end of 2020 were under budget at $899.6 million.

Analysis of metrics over the implementation period shows increasing benefits to the company, customers, and community.

B. Background

In 2009 ComEd piloted AMI meters and technology at 128,000 locations in suburban communities and the City of Chicago to gain information about the costs and benefits of deploying AMI. ComEd deployed more than 100,000 AMI meters and supporting infrastructure into nine suburban communities and another 30,000 meters in the City of Chicago. ComEd provided customers participating in the pilot with in-home energy usage displays and daily pricing notifications. The program tested various dynamic-pricing rates, including real-time, peak-time, time-of-use, and flat rate pricing.

In April 2012 ComEd filed its Smart Grid Advanced Metering Infrastructure Deployment Plan (AMI Plan or Plan) with the ICC. ComEd's Plan detailed capital investments in AMI technologies over 10 years to deploy smart meters and across its entire service territory. The primary goals focused on enhancing operational efficiency and providing customers with information and tools to manage energy consumption and costs better. The ICC determined ComEd's Plan met EIMA conditions and approved it with modification designed to expand tracking metrics and require coordination with the Smart Grid Advisory Council to explore ways to maximize dynamic pricing. The Smart Grid Advisory Council, established by the Illinois General Assembly, comprises nine voting members, with each member expected to possess either technical, business or consumer expertise in Smart Grid issues. The Governor appoints five members, and the Speaker of the House, Minority Leader of the House, President of the Senate, and Minority Leader of the Senate each appoint an additional member.

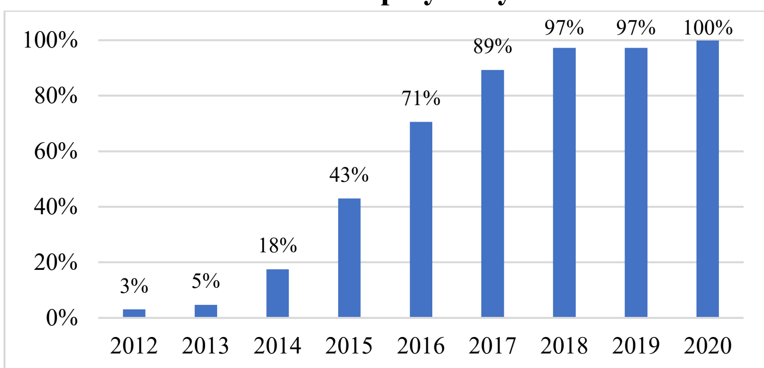
ComEd submitted a revised AMI Plan in October 2012; the ICC approved it in December 2012. The ICC approved ComEd's accelerated deployment schedule the following June with expected benefits projected to be five percent higher than that originally proposed for a projected two percent higher cost.

The ComEd project team spent much of 2012 planning, establishing the project management office (PMO), selecting service providers and technologies, and investigating customer-facing applications and education programs. ComEd selected Accenture as the Business Process and Systems Integrator and West Monroe Partners and Deloitte to provide PMO services. ComEd also began development of a Peak Time Rebate program.

In 2013 ComEd focused on readying systems and supporting technologies. IT replaced the pilot Meter Data Management System (MDMS) with a new MDMS capable of handling full AMI deployment and upgraded the supporting AMI communications network's head-end operating system to support full deployment and ongoing operations. Additionally, ComEd enhanced the web portal "My Energy Tools" to provide the ability for customers with smart meters to set up usage alerts and view bill projections.

ComEd began deployment of AMI meters in the fall of 2013 and completed installation in December 2018. The following chart shows progress as a percentage of AMI meters installed from 2012 through 2020. ComEd replaced nearly all electric meters within its service territory with AMI meters. As of the end of 2019, customers requesting or enrolled in non-standard metering numbered about 5,600.

MI Meters Deployed by Year



Percentages are of total installed meters

C. AMP Program - Progress by Year

In April of each year, beginning in 2013, after consultation with the Smart Grid Advisory Council, ComEd prepared and submitted a report detailing progress of the AMI Plan, including AMI investments during the prior year, planned AMI investments in the coming year, progress in meeting Plan metrics and milestones, and any updates to the plan.

1. 2012 – Program Year One

The first year of the project involved planning and selection of technology vendors. ComEd's Business Transformation team reviewed and documented business processes affected by the deployment. Requests for Proposals (RFPs) were created and issued to select qualified vendors. To oversee and support the initiative, ComEd established a PMO. Ahead of the planned 2013 launch ComEd delivered AMI presentations and roadshow demonstrations to employees to improve awareness of AMI technology and benefits.

The following table details 2012 year-end totals for AMI deployment. ComEd deployed the bulk of the AMI meters and equipment as part of its AMI Pilot prior to 2012.

2012 Cumulative AMI Deployment

Measure	Status
AMI Meters Installed	127,857
AMI Meters Refused	52
% AMI Meters Actively Billing	3.03%
% Network Equipment Installed	.03%
Total Capital Expenditures	$0.3 million

2. 2013 – Program Year Two

Vendors were selected to lead change management initiatives and to manage the project. ComEd began deployment in the Maywood service area, installing more than 70,000 meters and supporting network equipment. Deployment followed in South Chicago, with the installation of AMI network infrastructure. ComEd also upgraded the head-end system to prepare for system-wide implementation. The following table details 2013 year-end totals for AMI deployment.

2013 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	198,739
AMI Meters Refused	197
% AMI Meters Actively Billing	4.7%
% Network Equipment Installed	1.4%
Total Capital Expenditures	$42.9 million

3. 2014 – Program Year Three

ComEd revamped deployment plans to accommodate the revised and accelerated AMI deployment plan, with plans to complete installation by year-end 2018. ComEd's information technology (IT) department created an AMI dashboard to communicate daily progress of the deployment to the team and to executives. IT also replaced the AMI pilot MDMS with Oracle's MDMS to support the expanded deployment. Additionally, ComEd integrated the AMI systems with the Outage Management System (OMS) to facilitate easier identification of outages and to verify restored service. ComEd's IT department deployed Detectant software to monitor system and network health and performance, installed KeySafe to provide secure AMI network communications, and to support business continuity, established a disaster recovery plan for the AMI technologies.

AMI network design and installation continued in various locations. ComEd partnered with several firms to assist with field installation of access points and relay equipment. ComEd, with agreement from the International Brotherhood of Electrical Workers (IBEW) local, expanded its meter and network installation workforce to support the accelerated AMI plan. More than 540,000 AMI meters were installed in 2014.

The AMI team created an informational YouTube video, conducted outreach events, and provided other communications to customers to promote the AMI program and smart metering benefits. The AMI team conducted activities with employees to increase awareness of AMI impacted business processes and created a formal training program for impacted functions. In October, ComEd launched the Peak Time Savings (PTS) program, opening enrollment to all residential customers with smart meters. The following table details 2014 year-end totals for the program.

2014 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	739,483
AMI Meters Refused	1,106
% AMI Meters Actively Billing	18.0%
% Network Equipment Installed	20.2%
Total Capital Expenditures	$194.5 million

4. 2015 – Program Year Four

ComEd exceeded its AMI deployment goals for 2015, installing more than one million meters and associated AMI communications equipment and started installation of polyphase AMI meters for large commercial and industrial customers. The AMI team focused on minimizing meter exchanges that could not be completed due to access or issues with customer premise equipment. More than 100,000 meter exchange issues were resolved in 2015, through efforts of the team and special outreach initiatives.

ComEd deployed Green Button Connect My Data in 2015, providing a way for customers to authorize the exchange of usage data with authorized third-party suppliers. Customers can access the Green Button functionality through the ComEd website along with other energy analysis tools and information.

AMI Operations expanded data analytics and reporting to take advantage of AMI alarms and automated system events, reducing the need to resolve issues in the field. ComEd deployed appointment scheduling software to facilitate meter exchanges during times more convenient to customers. More than 97,000 customer appointments to exchange a meter were completed in 2015.

ComEd held meetings with local officials in wards or municipalities prior to deployment within an area to inform leaders of the scheduled installations and address concerns. ComEd customer communications continued to provide information about AMI technology and highlight benefits to customers.

ComEd further integrated AMI functionality with OMS to automate real-time meter status checks to determine if service is active (or not) and to relay results to the customer portal when a customer reports an outage on ComEd.com. ComEd enabled the remote connect and disconnect functionality to permit service to be turned on or off without the need of a field visit. Enhancements to data analytics led to more efficient back-office processing and the reduction in truck rolls to resolve issues. The following table details 2015 year-end totals for the program.

2015 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	1,817,241
AMI Meters Refused	1,832
% AMI Meters Actively Billing	43.0%
% Network Equipment Installed	50.0%
Total Capital Expenditures	$438.1 million

5. 2016 – Program Year Five

Meter deployment continued in 2016 with more than 1.1 million meters installed. ComEd completed installation within the Chicago Loop as well as at O'Hare and Midway Airports, all of which required unique communications solutions. AMI Operations enhanced its tools and systems supporting daily AMI network operations including, expanded reporting, data analytics solutions to address real-time notifications, key metric performance tracking, and enhancing field order dispatching based on meter data and status information provided through the network.

In 2016, a majority of ComEd customers had begun to take advantage of direct customer benefits including monitoring of interval energy usage data and enrollment in dynamic customer programs, such as Peak Time Savings and real-time pricing. ComEd also introduced a smart thermostat program for customers choosing to participate in the Air Conditioning (AC) Cycling Program.

Other ComEd operating groups used AMI data to support power factor monitoring, hosting capacity analysis, predicting transformer failures, voltage optimization, and outage verification. ComEd reported it avoided nearly 37,000 outage restoration-related truck rolls due to the ability to verify if AMI meters were energized. Close to 60,000 AMI notifications were generated by the meters alerting operations personnel to outages. The following table details 2016 year-end totals for the program.

2016 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	2,982,983
AMI Meters Refused	3,321
% AMI Meters Actively Billing	70.6%
% Network Equipment Installed	82.5%
Total Capital Expenditures	$672.1 million

6. 2017 – Program Year Six

ComEd installed 789,307 meters in 2017, exceeding planned deployment targets and essentially completing design and deployment of the AMI network. ComEd charged an Operating Area Close-out Team to address areas where AMI exchanges could not be completed to maximize meter deployment. The AMI team developed the Smart City Lab, which provides meter and communications testing in an environment that supports development of Smart City technologies to leverage AMI data and network.

ComEd launched an Internet of Things program to help residential hourly pricing customers and Peak Time Savings (PTS) customers automate responses to changes in hourly pricing or notifications concerning PTS. The program uses the IFTTT (If This Then That) application that provides easy scripting to automate devices connected to the internet.

During 2017 customers could elect to provide usage data to authorized third parties using the Green Button Connect feature on ComEd's website. Additionally, ComEd made it possible for external parties to purchase anonymized interval data. IT monitored the AMI network for vulnerabilities and security issues and conducted cybersecurity testing and enhanced network protection from external intrusion. The following table details 2017 year-end totals for the program.

2017 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	3,772,290
AMI Meters Refused	4,669
% AMI Meters Actively Billing	89.3%
% Network Equipment Installed	93.1%
Total Capital Expenditures	$820.6 million

7. *2018 – Program Year Seven*

ComEd completed the AMI deployment in 2018, installing more than 330,000 meters. The team focused on optimizing the AMI network communications and ramping down installation efforts.

In December ComEd launched the Green Power Connection Toolkit to help interested customers evaluate solar options. Additionally, the IT department implemented Chatbot technology on the website to provide an easy customer interface for requesting account balances, reporting outages, getting outage status updates, and for requesting other energy information. Customers can interact with the chatbots on the website or install on a home device such as Amazon Alexa or Google Home and Assistant. The following table details 2018 year-end totals for the program.

2018 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	4,107,521
AMI Meters Refused	5,632
% AMI Meters Actively Billing	97.2%
% Network Equipment Installed	94%
Total Capital Expenditures	$889.7 million

8. 2019 – Program Year Eight

ComEd's Operating Area Closeout Team worked to resolve remaining non-AMI meters on the system through exchange, enrollment in the non-AMI meter rider, or through physical removal. AMI Operations worked to optimize network communications to improve response as needed.

ComEd established the Smart Meter Operations team, organizationally responsible for AMI operations, field and meter service functions, revenue protection, data analytics, and AMI engineering and testing. Resources from the AMI project team transitioned to the new organization.

ComEd investigated opportunities to leverage the AMI network as a service to other utilities and municipalities. Several proof-of-concept studies were conducted with municipalities to read water meters as a service through ComEd's AMI network. The following table details 2019 year-end totals for the program.

2019 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	4,108,676
AMI Meters Refused	5,569
% AMI Meters Actively Billing	97.2%
% Network Equipment Installed	97.7%
Total Capital Expenditures	$899.6 million

9. 2020 - Program Year Nine

In 2020 ComEd continued customer outreach and education to highlight the benefits of AMI metering technology and to promote PTS, Hourly Pricing, and AC Cycling programs. The following table details 2020 year-end totals for the program. There were no capital expenditures associated with the AMI deployment in 2020.

2020 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	4,219,284
AMI Meters Refused	5,569
% AMI Meters Actively Billing	99.9%
% Network Equipment Installed	100%
Total Capital Expenditures	$899.6 million

10. 2021 - Program Year Ten

ComEd intends to provide the annual report for year ten of the program in April 2022. According to the Infrastructure Investment Plan (IIP), there were no planned AMI capital investments in 2021.

D. AMI Characteristics and Condition

1. Metering and Network Technology

ComEd deployed Aclara AMI meters, Itron's UtilityIQ head-end system, and MDMS. To provide the wireless mesh network technology, ComEd selected Silver Spring Networks (acquired by Itron in 2018). ComEd deployed more than 9,000 access points, relays, and other network equipment within its service territory to communicate with AMI meters. Meters record electric consumption in thirty-minute intervals to facilitate monthly customer billing. Access Points gather usage data from meters to the head-end system. Relays are used to transmit meter data to access points in areas of lower density. ComEd's smart meters support connectivity to a customer's Home Area Network (HAN) and customers can register and enroll approved energy monitoring devices through the ComEd customer portal.

2. Coverage

ComEd deployed nearly 100 percent of AMI meters throughout its service territory; about 5,500 customers have opted out of AMI meters in favor of non-standard meters. ComEd deployed the AMI meters and supporting network and systems over a 5-year period from 2013 to 2018, building on a 2009 AMI pilot which installed approximately 130,000 AMI meters.

3. Performance

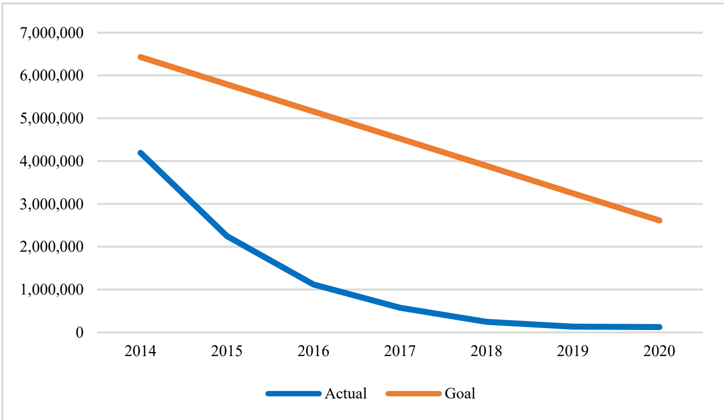
EIMA requires annual reporting documenting performance on multi-year metrics. The ICC approved ComEd's Multi-year Performance Metrics plan in January 2012. The plan included goals to reduce the following four AMI related metrics by year-end 2023 by the following amount, compared to a baseline:

- Estimated bills: 90 percent reduction
- Consumption on inactive meters (kWh): 90 percent reduction
- Non-technical line loss unaccounted for energy: 50 percent reduction
- Uncollectible expense: $30 million reduction.

a. <u>Estimated bills</u>

ComEd reduced the volume of estimated bills delivered to customers starting in 2014, when AMI meters began to come online. Over the subsequent seven-year period, estimated bills declined from 9 percent to 0.3 percent. AMI meters gather customer usage data more effectively from meters through the AMI network rather than collected manually by meter readers. As a result, ComEd billed more customers based on actual usage rather than estimated usage, a benefit for both customers and the company. Historically, estimated bills have proven a concern for customers, stimulating calls to customer service and often complaints to regulators. ComEd's AMI deployment reduced the level of estimated bills from more than 4.1 million annually in 2014 to 124,469 in 2020.

Estimated Bills



Actual vs. Goal Estimated Bills

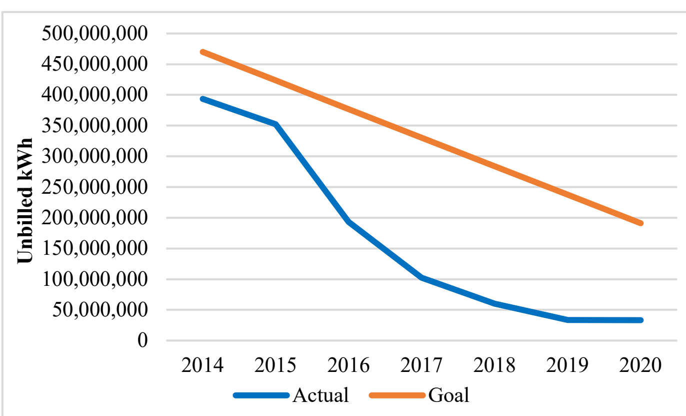
Year	Actual	Goal
Baseline		7,067,947
2014	4,194,878	6,431,831
2015	2,246,617	5,795,715
2016	1,116,675	5,159,599
2017	573,558	4,523,483
2018	243,612	3,887,367
2019	134,660	3,251,251
2020	124,469	2,615,135
2021		1,979,019
2022		1,342,903
2023		706,787

As part of EIMA, ComEd committed to reducing estimated electric bills by 90 percent over the 10-year period from 2014 to 2023. ComEd's 2020 estimated bill performance well surpassed the 2020 goal of 2,615,135 and the 10-year goal of 706,787 or fewer estimated bills.

b. Consumption on Inactive Meters

ComEd considers consumption on inactive meters for any usage registered on a meter at a location in which there is no customer on record to bill. To determine the amount, ComEd measures usage from the time a customer moves out until another customer moves in. Since 2014, ComEd reduced consumption on inactive meters dramatically, from 393 million kWh to 32 million kWh in 2020, as seen in the following table and chart.

Consumption on Inactive Meters (kWh)



Actual vs Goal Consumption on Inactive Meters (kWh)

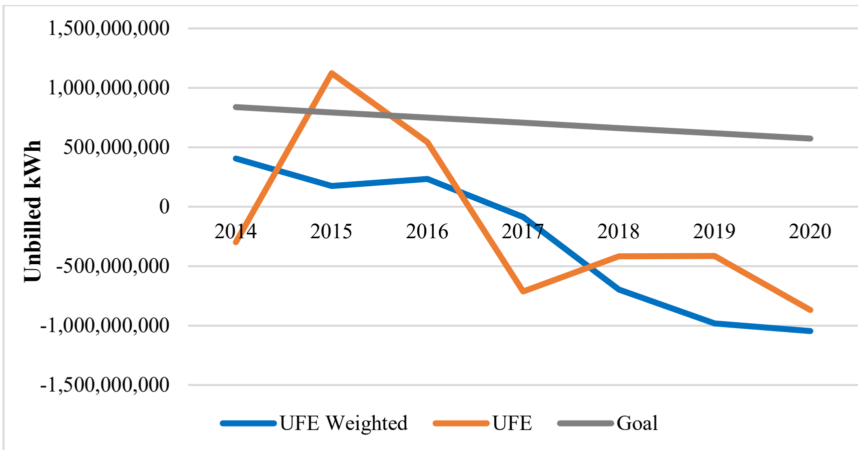
Year	Actual	Goal
Baseline		516,405,909
2014	393,478,189	469,929,377
2015	352,275,519	423,452,845
2016	193,052,918	376,976,313
2017	102,134,699	330,499,781
2018	59,920,741	284,023,249
2019	33,473,728	237,546,717
2020	33,276,582	191,070,185
2021		144,593,653
2022		98,117,121
2023		51,640,589

In conjunction with its participation in EIMA, ComEd committed to reducing consumption on inactive meters by 90 percent over the 10-year period from 2014 to 2023. ComEd's 2020 performance surpassed the 2020 goal of 191 million kWh and the 10-year goal of 51 million kWh or less.

c. Unaccounted for Energy

ComEd defines unaccounted for energy (UFE) as unmetered electricity that cannot be billed to an individual retail customer, often due to theft of service. ComEd's UFE, measured with and without a weighted value to minimize the impacts of summer weather, remained under goal from 2014 through 2020. ComEd committed to reducing UFE by half over the 10-year EIMA measurement period and actual performance met the 10-year goal in each year except for 2015, as seen in the following chart and table. When tracked using the weighted UFE metric, ComEd met the EIMA goal in all years since 2014. In both cases, UFE trended down since AMI deployment.

Unaccounted for Energy



Actual vs Goal Unaccounted for Energy (kWh)

Year	UFE	UFE Weighted*	Goal
Baseline			881,969,000
2014	-297,808,291	405,221,951	837,870,550
2015	1,123,295,717	173,727,762	793,772,100
2016	543,835,772	232,167,231	749,673,650
2017	-711,972,219	-86,962,719	705,575,200
2018	-417,301,830	-696,431,525	661,476,750
2019	-414,037,956	-981,673,051	617,378,300
2020	-869,360,760	-1,046,350,255	573,279,850
2021			529,181,400
2022			485,082,950
2023			440,984,500

* Weighted to minimize summer weather impacts on Unaccounted for Energy

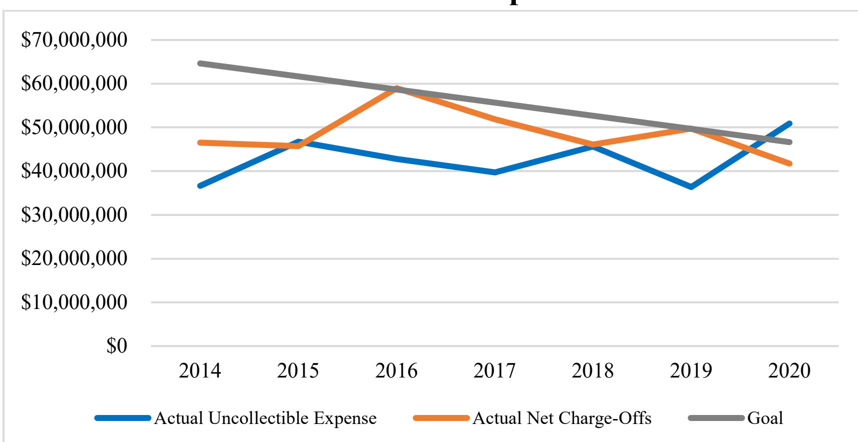
d. Uncollectible Expense

ComEd defines electric uncollectible expense as customer debt owed but not collected after reasonable efforts. ComEd's uncollectible expense remained under goal from 2014 through 2019.

Uncollectible expense in 2020 exceeded the goal during the COVID-19 pandemic and the Public Health Emergency declared on March 9, 2020, by the Illinois Governor. In response, the ICC ordered a moratorium through March 31, 2021, on disconnections of utility service and suspension of late fees and penalties, to ease economic hardships on customers during the pandemic. As a result, accounts receivable balances related to deferred payment arrangements and past due balances grew significantly during this period resulting in an increased uncollectible expense.

Due to increases in customer switching to alternative suppliers and other factors, ComEd introduced an alternative metric to track bad debt expenses -- net charge-offs – which includes retail customers and customers with alternative suppliers. This metric is presented annually in the following table and chart, along with the actual uncollectible expense and the yearly EIMA goal.

Uncollectible Expense



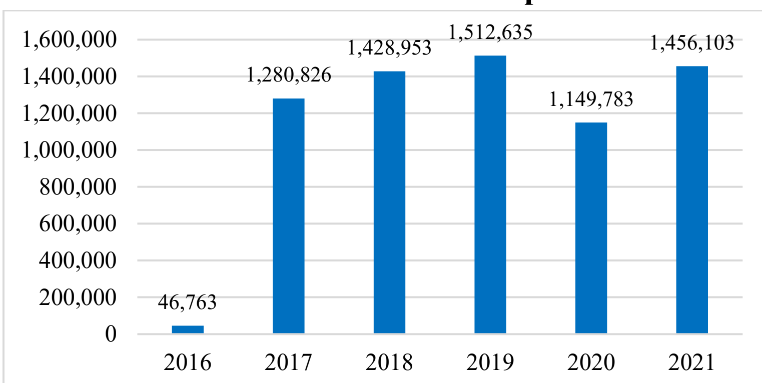
Actual vs Goal Uncollectible Expense

Year	Actual Uncollectible Expense	Actual Net Charge-Offs	Goal Uncollectible Expense
Baseline			$67,637,205
2014	$36,643,927	$46,511,162	$64,637,205
2015	$46,716,946	$45,692,405	$61,637,205
2016	$42,768,240	$58,979,270	$58,637,205
2017	$39,744,280	$51,854,650	$55,637,205
2018	$45,624,454	$46,071,332	$52,637,205
2019	$36,370,998	$49,753,261	$49,637,205
2020	$50,901,861	$41,725,627	$46,637,205
2021			$43,637,205
2022			$40,637,205
2023			$37,637,205

e. Other Operational Metrics

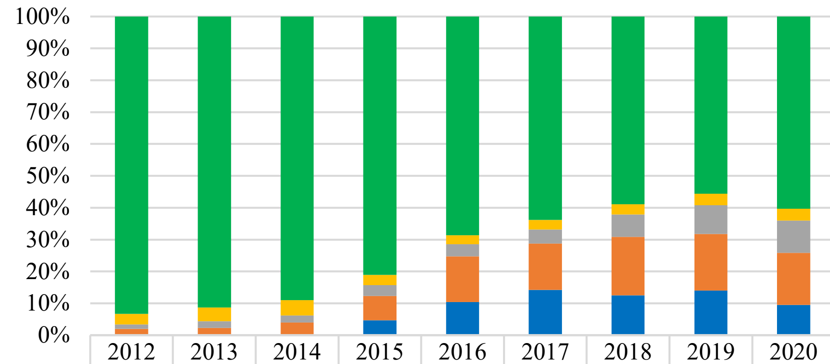
ComEd's tracking of the number of remote service orders (*e.g.,* connects, disconnects) completed through AMI shows a positive trend. From 2016 to 2021 ComEd completed 6.9 million service orders remotely, eliminating the need to complete these orders in the field. ComEd's remote service order functionality uses over the air commands to connect and disconnect service. Customers can request and schedule service on or off using the company website or when speaking with a customer service representative. ComEd also uses this functionality to perform cut-outs on delinquent accounts and to reconnect once a customer meets the payment criteria. Other remote service orders are conducted to retrieve meter readings on-demand to support billing or respond to customer inquiries.

Remote Service Order Completions



Customers have multiple options to alert ComEd to an outage at their location: call the contact center, self-serve using a mobile app, website, IVR, or by texting "OUT." ComEd tracks outage calls or notifications received by each communications channel. Since AMI deployment began, AMI outage notifications have increased, reducing the need for customers to call or contact ComEd through the various self-service channels. ComEd averaged about 11 percent of outage notifications received from AMI meters since 2015. Outage notifications received through AMI and customer self-service channels increased over the measurement period, reducing the need for customers to speak with a customer service representative.

Outage Notifications by Channel

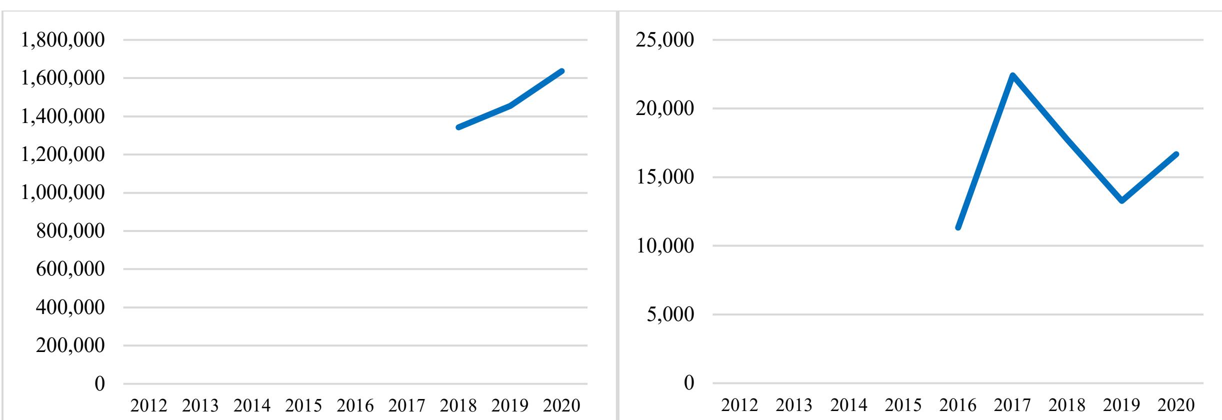


	2012	2013	2014	2015	2016	2017	2018	2019	2020
Phone/IVR	93%	91%	89%	81%	69%	64%	59%	56%	60%
Text	3%	4%	5%	3%	3%	3%	3%	4%	4%
APP	1%	2%	2%	3%	4%	4%	7%	9%	10%
Web	2%	2%	4%	8%	14%	15%	18%	18%	16%
AMI	0	0	0	5%	10%	14%	13%	14%	9%

ComEd enhanced its customer web portal in 2018 to provide customer access to AMI usage data, billing history, green-button functionality, and energy saving tips. Customers accessing ComEd's web portal increased quickly from 2018 to 2020, as more AMI meters came online and ComEd encouraged customers to sign up and access the portal. Customers also visited the Green Button web page beginning in 2016, with visitations peaking in 2017.

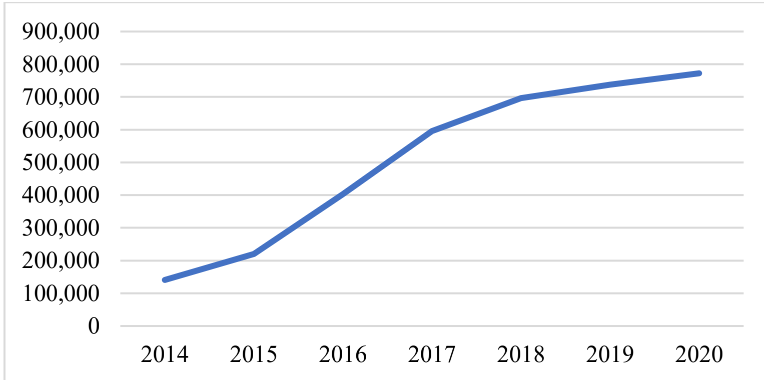
Unique Customers Accessing

Web Portal **Green Button**



Customer participation in Hourly Energy Pricing, Peak Time Savings, and AC Cycling increased steadily since 2014, as depicted in the following chart.

Customer Participation in Residential Demand Response and Dynamic Pricing Rates



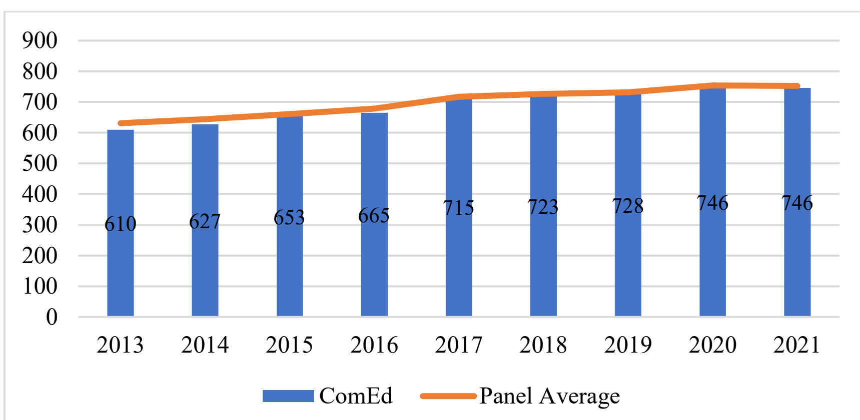
ComEd received more than 11,000 AMI-related customer complaints during the 10-year deployment, averaging about 28 complaints per 10,000 meters installed. Complaints include formal and informal complaints to the ICC as well as escalated complaints, and other non-ICC complaints.

AMI-Related Complaints Received

2012	2013	2014	2015	2016	2017	2018	2019	2020
56	230	1,388	1,616	3,425	2,759	2,340	49	n/a

ComEd's residential customer satisfaction improved steadily over the last 10 years, as measured by the J.D. Power Electric Utility Residential Customer Satisfaction Study.

Residential Customer Satisfaction



4. AMI Network Performance

ComEd's AMI Operations, Exelon Information Technology, and Itron monitor AMI network performance and health. Itron maintains a Network Operations Center (NOC) that monitors network equipment and the head-end software on a 24/7 basis.

5. Cybersecurity

ComEd created its AMI network as an isolated network, meaning no external access or exposure to the Internet. ComEd secured the network through a firewall that controls access and provides encryption. Any devices attached to the network must be registered and contain a security certificate to allow for authentication. ComEd conducts quarterly reviews to ensure that authorized users are provisioned to access the network. Hosted services provided by Itron are audited annually and Exelon Corporate Information Security Services conducts periodic cybersecurity assessments of the network (based on National Institute of Standards and Technology framework). Additionally, ComEd conducts periodic penetration testing through a third-party.

6. Health Monitoring Practices

ComEd developed a Quarterly Business Review process that reviews AMI scorecards of system health and performance with other Exelon utilities and Itron. ComEd also implemented a Network Status dashboard to provide real-time meter and network health and monitor the network for anomalies. ComEd uses data analytics, advanced reporting, automated system events, alarms, and notifications to identify missing meter data, allowing operations to address issues over-the-air or through a field investigation.

ComEd conducted network optimization of the AMI network over several years during the deployment to improve performance. Multiple performance metrics were used to identify devices below threshold and additional access points and relay devices were deployed to strengthen network communications.

In 2015 ComEd commissioned an analysis of deployed smart streetlights, streetlights whose sensors use the AMI network to communicate. The analysis did not identify any adverse impacts on the AMI or Distribution Automation (DA) services enabling ComEd to expand its smart streetlight program.

ComEd contracted with Vencore Labs in 2016 to conduct an analysis of the AMI network to identify potential impacts to DA devices during large outages. Following the study ComEd worked with Itron to address the increased device-to-device congestion identified during the outage analysis.

7. Failure Rates – AMI Meter Replacements

ComEd replaced over 192,000 AMI meters prior to their end of expected useful life (20 years) since the start of deployment, as reflected in the following table. AMI meters replaced annually ranged from 0.7 percent in 2012 to 1.5 percent in 2013 and 2015. ComEd states that it does not track the reason for meter failure and that AMI meters may fail due to manufacturer defects, vandalism, tampering, or theft. Overall, ComEd returned under warranty 39 percent of meters replaced.

AMI Meter Replacements

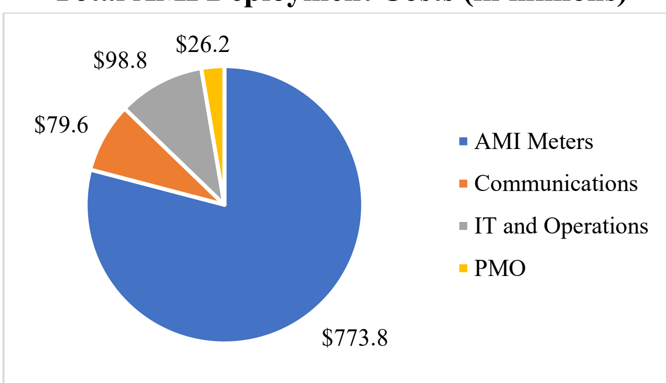
# of Meters	2012	2013	2014	2015	2016	2017	2018	2019	2020
Replaced	873	2,950	7,310	28,127	30,308	32,444	29,128	29,139	32,508
Installed	127,857	198,739	739,483	1,817,241	2,982,983	3,772,290	4,107,521	4,108,676	4,219,284
% Replaced	0.7%	1.5%	1.0%	1.5%	1.0%	0.9%	0.7%	0.7%	0.8%

E. Capital Investment

Enactment of EIMA allowed ComEd to embark on a multi-year Infrastructure Investment Plan (IIP) which provided additional investment in infrastructure and training with reliability being a key driver. Following the passage of EIMA, ComEd filed a proposed performance-based formula rate tariff in 2012, updated each year, under which it recovers electric delivery expenses. In each annual filing, ComEd identifies actual expenses and plant additions, and planned plant additions that support electric delivery service for the following year. AMI program capital costs comprise a component of ComEd's Smart-Grid related investments detailed in its IIP. ComEd submits annual reporting updating AMI expenditures and progress.

ComEd's actual AMI deployment costs from 2012 to 2020 totaled $899.6 million. Meter costs made up approximately 80 percent of costs at $707.6 million. Communications hardware and systems totaled $72.1 million and IT and Operations capital costs totaled $98.3 million. The AMI capital spending represents about 35 percent of the total EIMA IIP capital investment. ComEd did not invest capital in the program during 2020 or 2021.

Total AMI Deployment Costs (in millions)



AMI Costs	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
AMI Meters		$14.7	$101.1	$196.4	$197.9	$131.3	$60.8	$5.4		**$707.6**
Communications		$17.4	$8.0	$13.9	$15.8	$9.5	$5.3	$2.2		**$72.1**
IT and Operations		$10.1	$39.5	$28.9	$16.0	$3.3	$0.2	$0.3		**$98.3**
PMO		$0.4	$3.0	$4.4	$4.3	$4.5	$2.8	$2.0		**$21.4**
Total Actual	**$0.3**	**$42.6**	**$151.6**	**$243.6**	**$234.0**	**$148.5**	**$69.1**	**$9.9**	**$0.0**	**$899.6**
Allocated Budget	**$0.3**	**$42.6**	**$151.6**	**$243.6**	**$234.0**	**$148.5**	**$69.1**	**$9.9**	**$0.0**	**$899.6**

F. Impact

AMI operational benefits of streamlined billing, reduced field costs, and improved outage detection and reliability begin with deployment. However, the more challenging benefits to achieve involve changing tariffs, improving customer communications and customer tools, increasing customer participation and interaction, and leveraging analytics tools to pinpoint distribution system efficiencies. AMI deployment enables near-real time access to customer usage data. Data use determines success in reducing or shifting energy consumption, identifying failing equipment, optimizing system voltage, and supporting DER initiatives.

Many utilities have struggled to quantify AMI-enabled benefits beyond streamlined billing and meter-to-cash savings. Benefits such as smarter power outage detection, conservation voltage reduction, advanced rate design, and improved energy efficiency and demand response are harder to achieve, especially when requiring changes in customer behavior or customer participation. A recent American Council for an Energy-Efficient Economy Report found that "[t]he capabilities of AMI as an information resource and tool for customers to reduce their costs and achieve other benefits generally have been underutilized, as indicated by our utility surveys and interviews with industry experts."

However, regulators, with insight from industry research, have held utilities accountable for both operational and customer-oriented benefits, either through penalties or withholding reimbursement of capital expenditures if deployment targets are not met. EIMA and ComEd's AMI Plan, approved by the ICC, holds ComEd accountable for program spending and performance.

ComEd's AMI Plan for the accelerated deployment presented analysis reporting that the present value of benefits exceeds the present value of costs by $1.271 billion over a twenty-year analysis period. ComEd's AMI Plan identified many benefits associated with the deployment including:

- Reduced manual meter reading
- Reduced meter field work
- Reduced manual billing
- Reduced outage management effort
- Reduced call center effort
- Reduced consumption on inactive meters
- Reduced energy theft
- Reduced bad debt
- Avoided capital investment in equipment
- Improved customer access to usage information
- Enhanced rate options and services
- Improved customer experience
- Job creation
- Enabling Voltage Optimization operations
- Supporting integration of electric plug-in vehicles, distributed generation, and storage
- Enhanced data collection, analysis, and communications capabilities
- Enhanced applications to monitor, manage, and automate energy use in customer homes.

- Automation of electric grid functionalities.

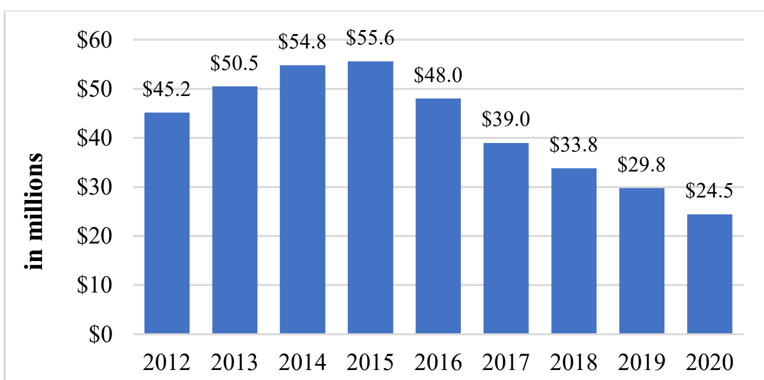
ComEd realized AMI benefits as soon as the technology became operational. Analysis of metrics over the implementation period shows increasing benefits to the company, customers, and community. The prior section's charts and tables document ComEd's performance on EIMA AMI-related performance goals – reducing estimated bills, reducing consumption on inactive meters, reducing unaccounted for energy, and a downward trend in uncollectible expenses (excepting pandemic year 2020). AMI technology enabled customers to take advantage of new pricing tariffs that encouraged energy conservation and provided reduced pricing and bill rebates for limiting usage during certain peak time periods. Customers also had access to more detailed and time usage information and energy saving tips. ComEd applied advanced analytics and reporting to identify meters requiring field investigation and potential theft of service and situations that could be resolved without a field visit. During outages, AMI was leveraged to determine meter status and identify locations still without service.

ComEd demonstrated improved operational performance through the following metrics, also detailed in the prior section's charts:

- Reduced customer calls/self-service to report outages through increased AMI notifications
- Increased customer access to AMI data on web portal
- Increased customer participation in Peak Rewards Program, Power Smart Pricing, Real-time Pricing, and other dynamic pricing rates.

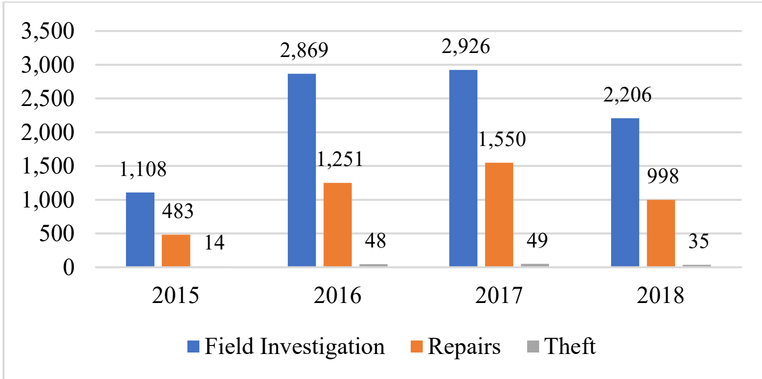
ComEd meter reading expenses (FERC 902) began declining in 2016 and have continued to drop as shown in the following chart. Meter reading expenses have declined due to the installation of AMI meters and through a significant reduction of manually read meters.

Meter Reading O&M Expenses



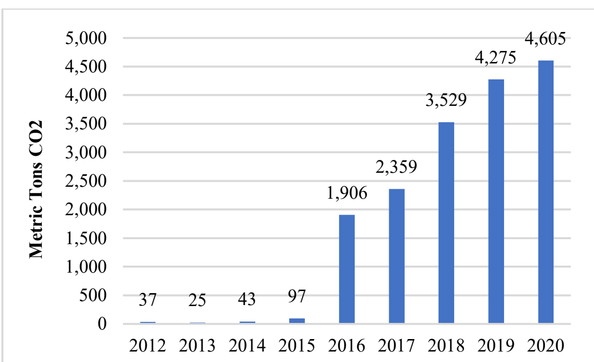
Beginning in 2015, ComEd used data analytics to proactively monitor AMI meters for high temperature variations and possible tampering incidents. When necessary, Field and Meter technicians are dispatched to investigate and resolve those situations. From 2015 to 2018 more than 13,500 instances were investigated leading to repair or replacement, as shown in the following chart.

Field Investigations

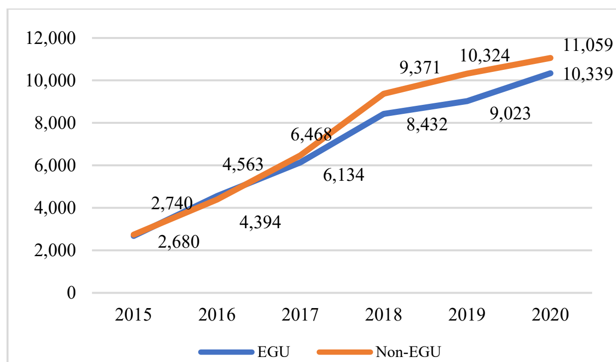


ComEd identified further savings through reduced emissions, achieved through the elimination of vehicle gasoline consumption and customer conservation efforts. The following charts depict ComEd's reduction in greenhouse gas emissions from vehicles (meter reader, outage, and maintenance) and energy conservation pricing programs (Hourly Pricing and Peak Time Savings), calculated by two methods, with and without Energy Generating Unit emissions data.

Reduced Greenhouse Gas Emissions - Vehicles



Reduced Greenhouse Gas Emissions – Hourly Pricing and Peak Time Savings



As a result of the AMI implementation, ComEd reduced operating expenses, improved operational efficiency, reduced greenhouse gas emissions, and expanded rate options and access to energy usage information for customers. Additionally, ComEd positioned the technology to support more advanced services and operational analysis such as voltage optimization and distributed energy resources (DER), and actively communicated with customers to increase awareness of the technology and its benefits.

IX. Distributed Energy Resources

A. Summary

Accommodating the interconnection of distributed energy resources (DERs) has not formed a normal part of the criteria under which ComEd planned and designed its distribution system across our study period. ComEd, however, has developed processes that allow for DER interconnections. The company's GIS (geographic information system) provides sufficient accuracy to permit it to study load flow capacities down to street addresses and ComEd has used it in producing a "DER hosting map" that shows customers and developers the best locations for DER interconnection applications. ComEd has a formal process for reviewing DER interconnection requests and for conducting application specific studies required for approvals of DER interconnection requests. Total DER interconnections (MWs) have increased in recent years but still remain a small fraction (about 2 percent) of total system load.

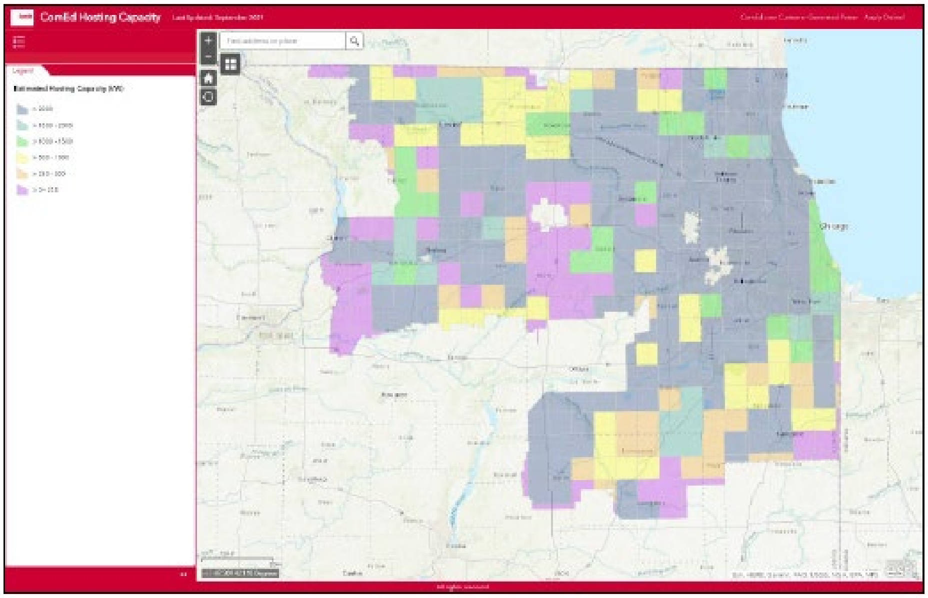
B. Determining Ability to Interconnect a Distribution DERs

DERs can produce value to the distribution grid by, for example contributing to feeder capacity, voltage control, and reliability. However, DERs interconnections can also raise practical, operational, or economic implications for the electric grid. ComEd has a DER Hosting Capacity Analysis tool that supports determination of the amount of DER capacity that can be interconnected to each circuit, without causing excessive forward and reverse loading, voltage, power quality criteria violations, or the need for system infrastructure upgrades. ComEd provides color-coded visualizations of DER hosting capacity at the feeder, township, section, one quarter-section, and even the one-sixteenth section levels.

C. Hosting Capacity

ComEd calculated, for each circuit, the kilowatts (kW) of DERs that it can interconnect without negatively affecting the operation of the grid. DER developers and customers use the Hosting Capacity map as an initial guide for selecting possible DER interconnection sites, depending on the kW involved. ComEd publishes the Hosting Capacity Map as a resource to DER developers and customers prior to initiating the interconnection application and approval process. When applicable, ComEd conducts interconnection studies before final approval to interconnect. The next image depicts ComEd's "DER hosting capacity map," which can expand down to the street level.

Hosting Capacity Map



D. The DER Interconnection Planning and Approval Process

DERs are generally categorized as follows:

- Renewable energy resources such as solar, wind, water, biomass, and geothermal
- Other generators fueled by methane produced in landfills
- Co-generation where electric energy is produced along with steam or heat.

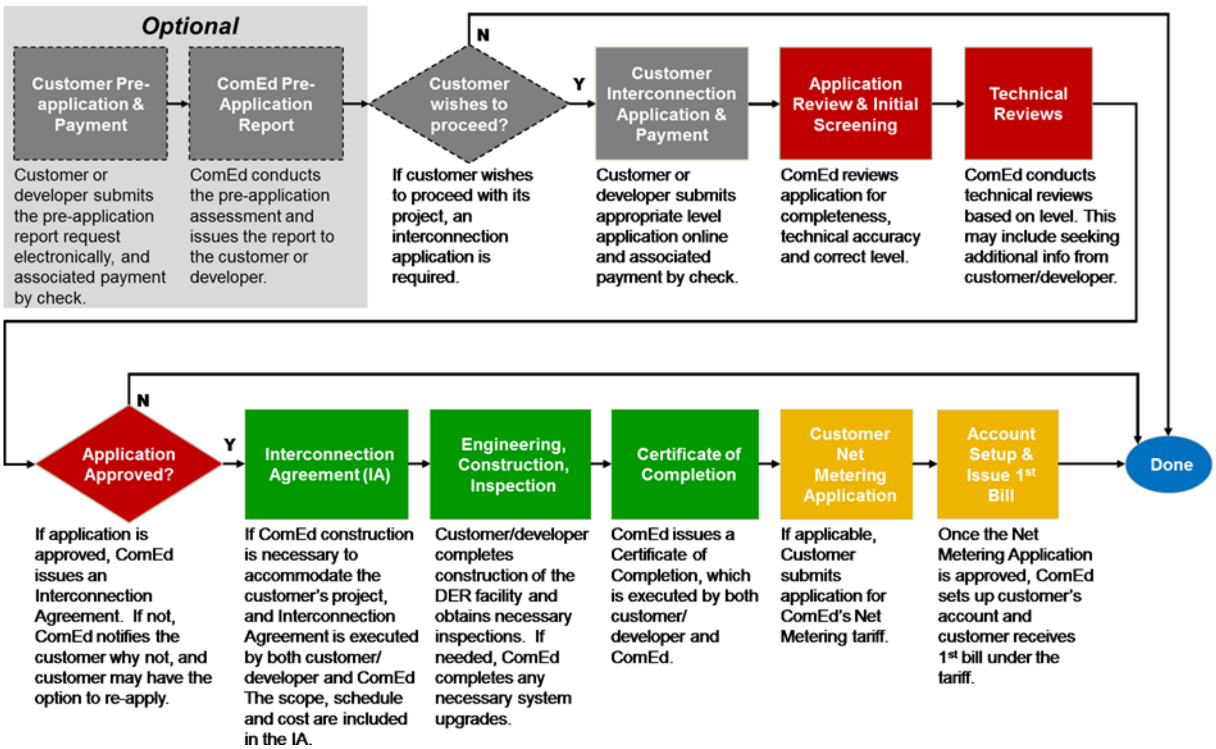
In Illinois, the interconnections of DER customers to the utility distribution grids are governed by the Illinois Administrative Code Title 83, Part 466 for interconnections of 10MW (a megawatt is 1,000 kilowatts) or less and Part 467 for interconnections of greater than 10MW. These codes require that the interconnecting customer design, install, provide relay protection, operate, maintain equipment in accordance with applicable Standards and Codes, and provide protection to the interconnected utility and its customers from faults on, and improper operations of, the DER systems and from other detrimental grid operating condition caused by the DERs.

Depending on the kW or MW (Megawatts) capacity of proposed DERs, and the determined detrimental effects to ComEd's distribution system, DER owners or developers have responsibility for the costs to upgrade ComEd's facilities to support the interconnection, including adding relay protection required to protect ComEd's system, the installations of communication, telemetry, and metering systems, and the relocating of facilities and upgrading ComEd's system. Later, DER customers must make necessary changes to their DER systems if required by ComEd because of changes in system loading or generation sources.

Some large DERs, including wind farms, large solar farms, or biomass generators, connect to the transmission system, requiring study and approval by PJM, the regional transmission organization (RTO) that coordinates the movement of wholesale electricity for all or parts of 14 states.

Developers applying for DER interconnection to ComEd's distribution system must follow the interconnection process which begins with an optional $300 pre-application fee and the completion of an on-line pre-application form. The customer or developer then submits its application and pays an application fee depending on the kW or MW of the DER, ranging in discrete steps from $50 for DERs of 25 kW or less up to $15,000 for DERs of 10MW and larger. The following diagram illustrates ComEd's DER interconnection process.

DER Interconnection Process

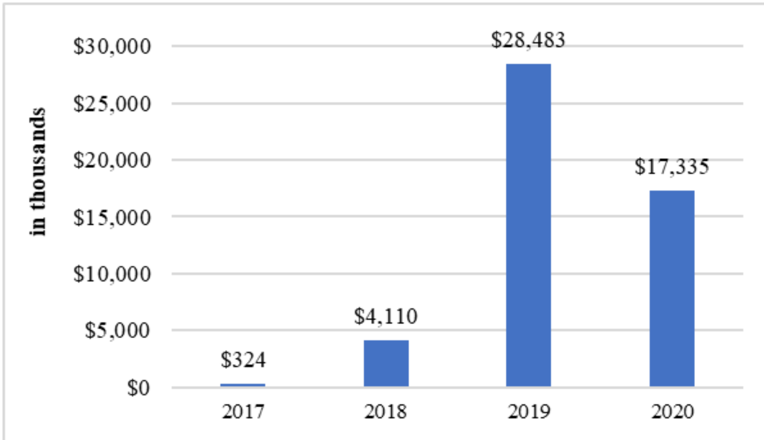


Before ComEd approves an application, it conducts a technical review of the proposed DER. ComEd may conduct a variety of studies (*e.g.,* short circuit, protection coordination, voltage, load flow, and stability) to ensure that each proposed DER interconnection application is consistent with ComEd's technical requirements, and that the DER will not adversely affect grid operations or other customers. ComEd also determines the required additional infrastructure, if any, and required SCADA, relaying, metering, fiber optics, microwave, or power line carrier communications, telemetry, and real estate. Before allowing the interconnection of a DER with the grid, ComEd may require review of relay settings and witness testing of DER operation and protective and control devices.

E. DER Integration Investments

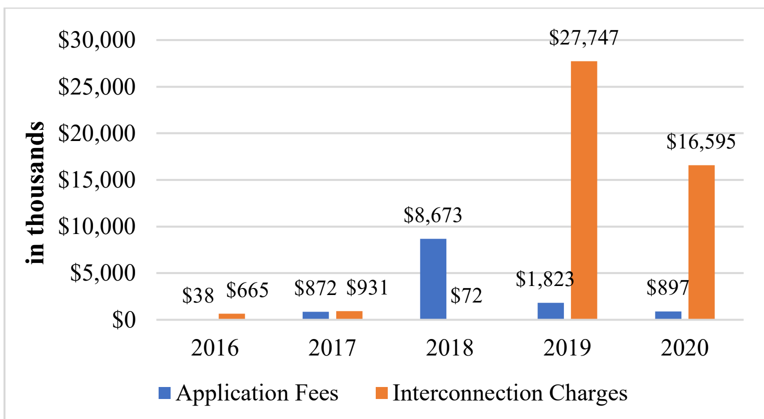
ComEd funded studies and projects required for understanding how to prepare the electric distribution system for DER integration, for developing tools to support DER integration through grid investments, and for developing online tools and systems to improve DER application processes. The following chart shows ComEd funded investments from 2017 to 2020. No reported investments occurred prior to 2017.

ComEd Funded Direct DER Integration Investments



As noted, ComEd charges DER developers and customers for direct investments associated with design, procurement, and construction of interconnection facilities, including electric distribution system upgrades necessary because of the DER facilities. The following chart presents DER interconnection customer and developer funded investments and fees for the period 2016 through 2020.

DER Interconnection Investments and Fees

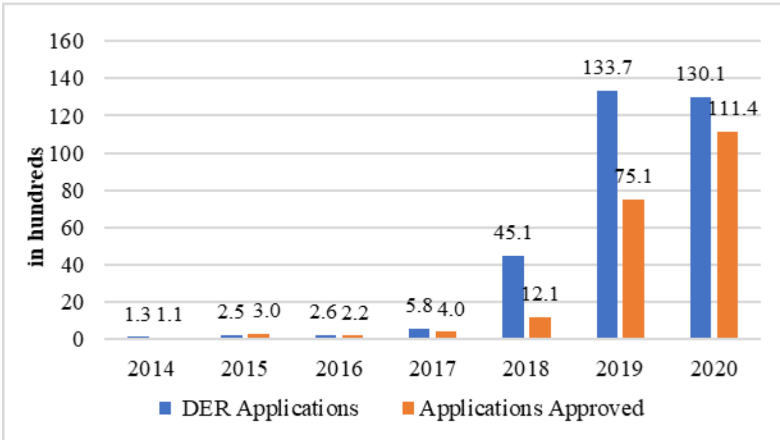


In addition to the DER interconnection investments funded by ComEd and the DER developers or customers, ComEd also made investments that may have provided indirect or secondary support or benefits for DER integration, without tracked expenditures to DER. These investments were included in capacity expansion, new business, and system performance investment categories. Capital projects in these categories provided distribution capacity, communications, SCADA monitoring, and control upgrades that indirectly benefit DER interconnections.

F. DER Interconnection Applications

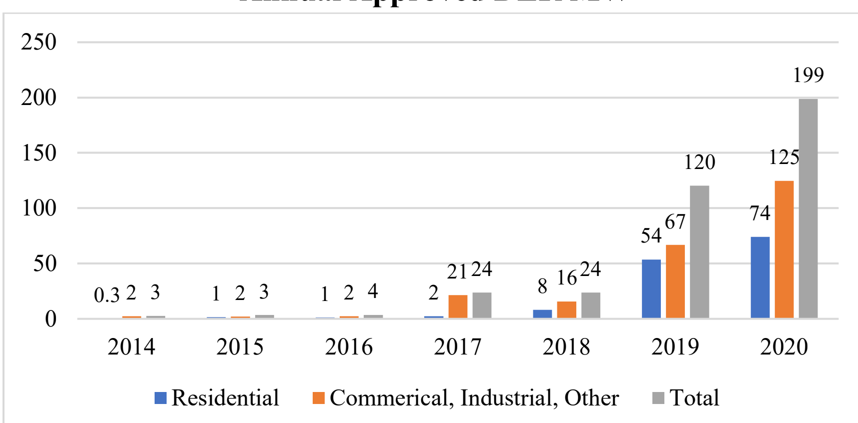
ComEd received and approved more than 30,000 DER applications from 2018 through 2020, as shown in the next chart (tracking began in 2014). More than 97 percent of the DER applications received and approved were residential interconnection. Less than three percent of the applications were for commercial, industrial, and "other" interconnections.

Annual Received and Approved DER Applications



The next chart shows that ComEd approved about 320MW of DER interconnections in 2019 and 2020. Residential applications comprised 97 percent of the DER applications, but more commercial and industrial and "other" categories covered more of the approved MWs. The approved MW of DER interconnections in 2020 included about 74MW from residential DERs and about 125MW from commercial and industrial, and other developers.

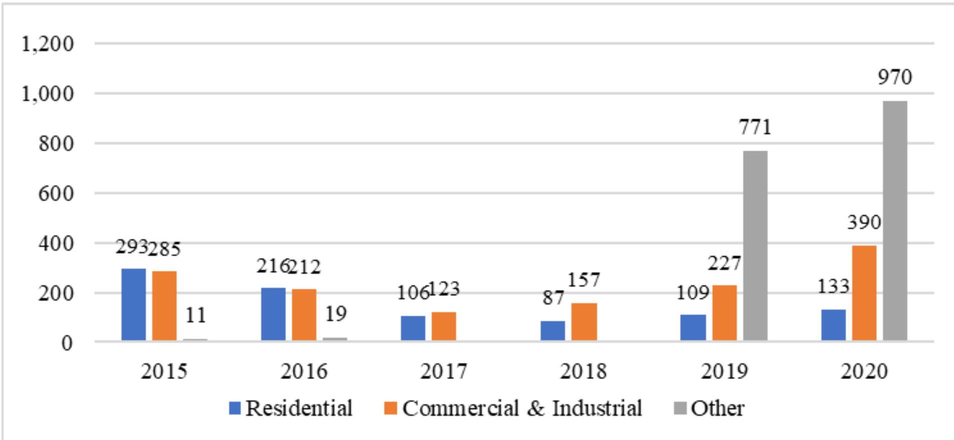
Annual Approved DER MW



G. Annual DER Interconnections and Energy Additions

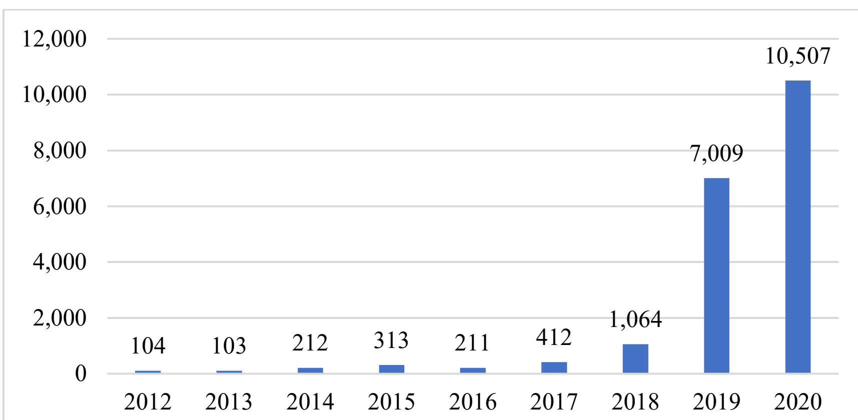
The next chart shows the time between DER application and interconnection completion. The average 2020 time between application and interconnection completion came to 133 days for residential (solar) DERs and 390 days for commercial and industrial DERs.

Average Days Between DER Application and Interconnection



The following chart shows that the numbers of DER interconnections to ComEd's system increased dramatically between 2018 and 2020, with only a few new interconnections for wind and miscellaneous types of DERs. Less than one percent of the DERs involved wind or other types of DERs, with nearly all for solar DERs. ComEd interconnected about 18,580 DERs to its distribution system, but only 12 transmission system interconnections from 2018 through 2020. Note that ComEd applies the term DER only to those interconnections made to its distribution system.

Annual Distribution DERs Interconnected



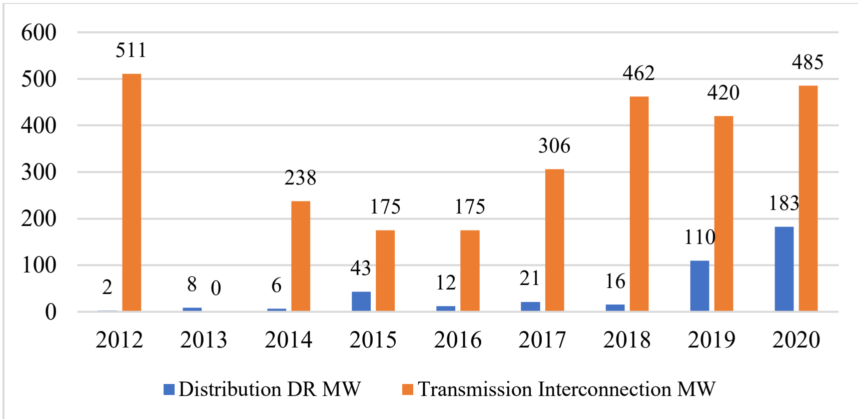
Very small numbers of transmission interconnections have occurred from 2012 through 2020, as shown in the following table.

Annual Transmission Interconnections

2012	2013	2014	2015	2016	2017	2018	2019	2020
6	0	1	2	2	1	3	3	4

ComEd reported that, as of the end of 2020, a total of 460 DER MWs interconnected with its distribution system. The next table shows the reported amounts of distribution and transmission interconnections in MW each year between 2012 and 2020. Transmission interconnections accounted for most of the MW interconnected until 2018.

Annual Distribution & Transmission Interconnection MW



X. Distribution System Planning

A. Summary

ComEd undertook structured and comprehensive capital planning and authorization processes during the study period, guided by planning criteria related to identifying system requirements with consideration of costs and exposure mitigation avoidance. Planning and authorization processes included sequentially executed screening and authorizing steps for capital projects over $100,000 following a formal process of need and cost-benefit challenges, approvals, and authorizations at management levels determined by the estimated costs and risks of the projects. ComEd conducted its projects in "phases" and reviewed and re-authorized the projects at each phase.

ComEd's Capacity Planning process included:

- Forecasting future peak loads based on expected new business connections, economic data, historical load data, and knowledge of local area planning engineers
- Adjusting forecasts for near worse case weather
- Identifying expected loading criteria violations
- Preparing best cost, lowest risk solutions for mitigating criteria violations
- Screening projects and challenging the need, the design, the risk of not attaining expected benefits, and the project costs of the primary and alternative solutions
- Authorizing, by management levels appropriate to project cost and risk, the best cost most likely to succeed project that resolves the criterion violation.

ComEd's processes for planning capital projects and programs for reliability and corrective maintenance largely followed those applicable to capacity projects.

B. Capacity Planning

ComEd's electric system comprises transmission lines, substations, and overhead and underground distribution circuits, service transformers, and meters. As discussed in Chapter IV: *System Description and Configuration*, ComEd's distribution system employs overhead and underground power line circuits, rated at various voltages, that connect to substations that convert those voltages to serve customers from overhead, ground mounted, and underground service transformers. System planning encompasses the numerous processes that are inter-related, technical, analytically complex, and critically important to ensuring safe, economical, and reliable delivery of energy to customers, particularly given the desire for, and impacts of, increasing third-party access to the grid and integration of distributed energy resources. Importantly, system planning also includes processes for capital allocation including comprehensive project screening, authorization, and prioritization to ensure that the projects provide the intended benefits before funds are spent.

The balance of this section presents and describes the following key system planning elements:

- Capacity Planning Overview
- Capacity Planning Criteria
- New Business Connections Planning
- Equipment Ratings
- Peak Load Forecasting

- Area Capacity Planning
- Substation Load Forecasting
- Long Range Capacity Planning.

1. Capacity Planning Overview

Effective system capacity planning ensures that the distribution system will continue to operate reliably within design criteria when distribution circuit and substation loads within a planning area change due to material changes in peak loads, load profiles, or power flows, as determined by load forecasting distribution planning processes.

The capacity of a distribution system to deliver power to customers reliably under normal and extreme temperature conditions drives fundamental design criteria. ComEd develops capacity relief plans or actions for circuits and substations forecasted to be loaded beyond design criteria under extreme weather conditions.

For distribution system capacity planning, ComEd collects load data on various portions of its system, including substations and distribution feeders, and forecasts the likely peak loads to be experienced in the future at design weather conditions. In arriving at these forecasts, ComEd accounts for past growth, new development plans, other planned customer expansion, and forecasts by consultants or local and regional governments. Planners within ComEd then analyze this data to determine where load will likely overload the system. In addition, planners evaluate the system under normal operating conditions and under a variety of contingencies to determine the extent to which reinforcement of the system proves needed.

The transmission system (not subject to review in this report) undergoes ComEd and PJM (the regional transmission organization) study to ensure compliance with North American Electric Reliability Corporation (NERC) Planning Standards, Exelon Transmission Planning Criteria, and PJM planning criteria. These standards require system planning, design, and construction that will permit it to withstand a variety of disturbances without experiencing overload of transmission elements, cascading interruptions, or uncontrolled loss of load, the impacts of which cascade to the distribution system.

The basic elements of a Distribution Capacity Planning Process include:

- Complying with Planning Criteria – The system must operate within equipment ratings and other operating criteria such as voltage limitations, and the ability to operate with one element *e.g.*, circuit segment or substation transformer, out of service. Such a condition is referred to as "N-1"; "N" denoting "normal" and "-1" meaning one supporting element out of service.
- Forecasting loads caused by planned new business connections.
- Forecasting future distribution circuits and substation peak loads – Planners forecast future peak loads, based on historical growth, planned new business connections, already planned changes to system capacity and configuration, along with the possible effect of extremely hot weather.
- Area Planning – ComEd's load has not been growing system-wide but has experienced some localized load growth. ComEd projects peak load growth at the area level and system

and area planners considers solutions to resolve forecast criteria violations and then select the best solution based on cost and the likely success of resolving the criteria violation.

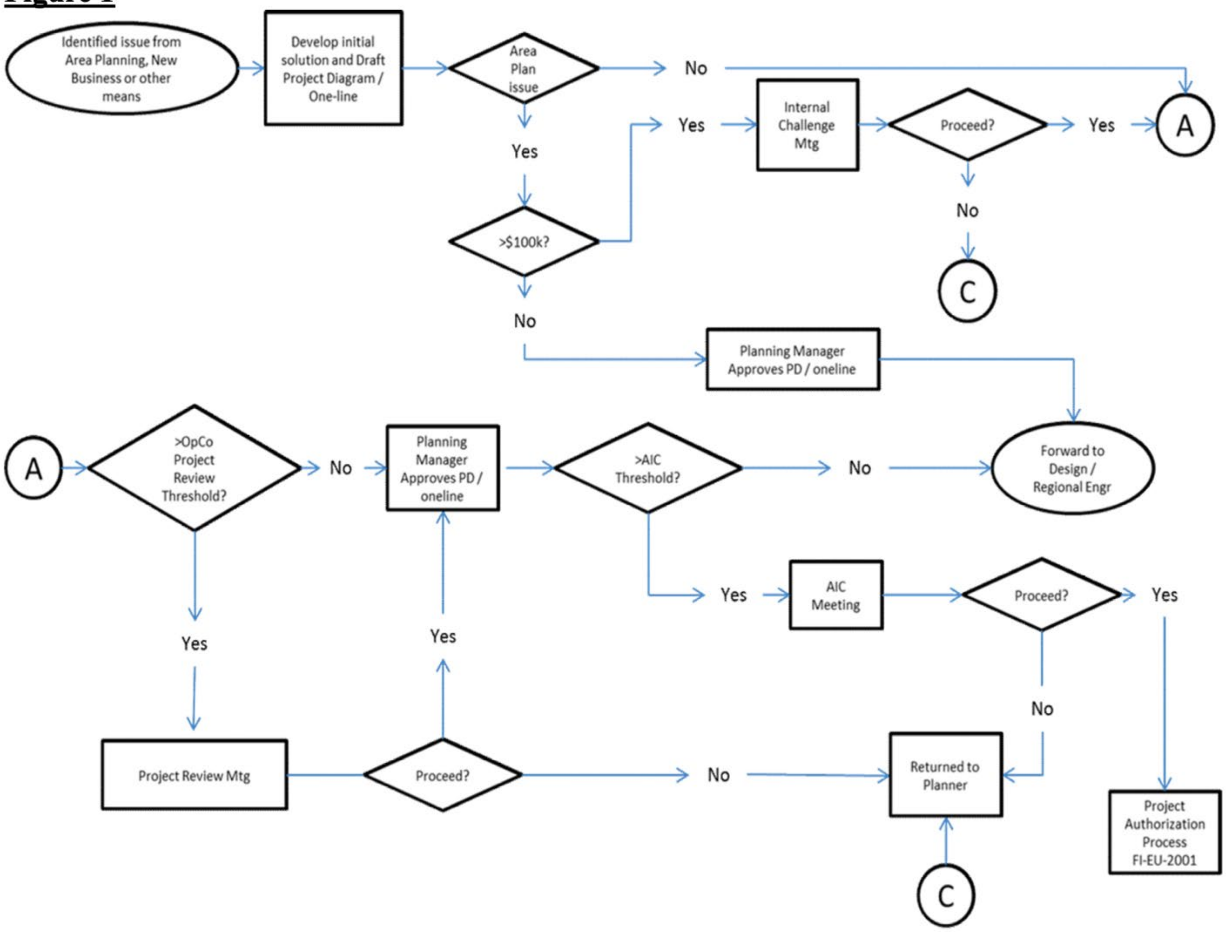
- Long-Range Planning – ComEd uses economic growth data to identify areas where it might require long-lead time new substations and transmission lines.

Area Planning, New Business, or other means identify capacity issues. Related projects may provide solutions from local a capacity issue involving a conductor or a component, to a capacity issue over a larger geographic area, or a capacity issue with an entire substation. ComEd's capacity planning process depends on the equipment encompassed, and, on the cost, as described by planning process steps indicated in the following figure. (ComEd updated this process in 2020, as described below.)

For proposed local area capacity planning projects under $100,000, a Planner develops proposed solutions and project diagrams. The Planning Manager reviews and approves a proposed solution description and one-line drawings, then forwards the proposal to Regional Design/Engineering to prepare the project. An internal challenge group reviews and approves proposed solution documents and one-line drawings for proposed local area projects over $100,000. Depending on the cost threshold limits, all proposed capacity projects may proceed to a project review meeting, or directly to the Planning Manager. Again, depending on cost threshold limits, the proposed project then goes to Regional Design/Engineering to prepare the project or to the Protection Concurrence Committee (PCC) that must authorize the projects costing greater than threshold amounts. ComEd updated the project authorization process in 2020. The revised process assesses each potential project to determine the appropriate level of PCC review - - those requiring a formal presentation and those reviewable by electronic feedback and authorization. As part of this process revision, ComEd consolidated the Asset Investment Committee meeting (depicted in the following figure) into the PCC meeting. We describe the formal PCC authorization process later in this chapter.

Capacity Planning Depiction

Figure 1



The following scenarios describe how ComEd plans solutions to capacity relief issues. Additional details about capacity planning procedures come later in this chapter. The hypothetical costs below represent Liberty assumptions.

Scenario No. 1: ComEd forecasts that a 4kV circuit would become overloaded by 25 percent in two years.

Assuming the solutions, such as increasing the size of conductors, or installing a circuit, hypothetically costs $400,000, an Area Planner would propose various solutions with project descriptions, one-line maps, and cost estimates to the project challenge group. The area planner and the challenge group determine the solution. The Planning Manager then reviews and approves the project description and one line map, then submits the project for review and approval by the Category Manager.

Scenario No. 2: ComEd forecasts that a 69/12kV substations transformer will become overloaded by 50 percent in 5 years.

Assuming the solution, such as installing a larger transformer, hypothetically costs $5,000,000, the capacity planning, transmission planning, and substation engineering groups would work together to develop possible solutions. The project determined would undergo challenge by Project

Review group and the Planning Manager before submission to the Department Vice President for authorization.

Scenario No. 3: An industrial customer requires an additional 2,500kVA of capacity served from existing 10,000kVA transformer and is currently loaded to 90 percent of capacity.

The New Business group would lead this project. Assuming the solution, such as installing a larger transformer hypothetically costs $500,000, the capacity planning, substation engineering, and New Business groups would work together to develop possible solutions. After engineering and the challenge group determines the best solution, the Planning Manager reviews and approves the project description, then submits the project for authorization by the New Business Manager.

Scenario No. 4: A housing development served by underground (URD) cable system plans to expand from 100 homes to 130 homes.

The New Business group, in consultation with the Capacity Planning group, would design and propose a solution. Assuming the solution hypothetically costs $90,000, Planning and New Business Managers would review it before sending it to the engineering groups.

Scenario No. 5: A large industrial customer desires to interconnect energy recovery co-generation to the distribution grid.

Based on the customer's interconnection application, capacity planning would evaluate the intended operation of the energy recovery system, the effect on the distribution grid, and the interconnected generation's dependability and dispatchability. Engineers would study the effects of the additional generation both during minimum and maximum circuit loads and determine any upgrades required to interconnect the customer.

2. *Capacity Planning Criteria*

ComEd engineers evaluate feeders and circuits to ensure that loads on those elements would not exceed 105 percent of normal capacity without violating certain criteria. The criteria require adequate interconnections in the event of failure to allow transfer of loads to other circuits within four hours or less. The criteria also require planning for distribution circuits in 400 to 750 customer blocks in order to take full advantage of distribution automation where applicable.

The planning criteria for secondary (low voltage) networks used in major urban areas require that systems have the capacity to allow normal operation with one out-of-service primary source or network transformer during a summer peak load season, or with two out of service primary sources or transformers during a non-summer peak season.

ComEd's distribution substations planning criteria require that substations have feeder tie capacity to permit load transfers among local area substations and to limit the average area total substation load to capacity ratio to about 95 percent in high growth areas and 98 percent in low growth areas. Many ComEd substations have redundant sources and buses, but those that do not require the Operations Department to use feeder ties, emergency feeders, mobile substations, mobile generators, or using automatic load shedding to avoid cable and conductor damage for extended transformer overload conditions.

3. New Business Planning

New business connections account for most load growth. The New Business capital category includes costs for the work required to connect new customers, to upgrade customer services, and to relocate non-municipal services. New Business includes baseline projects (day-to-day new connections and relocations) internally worked for less than $100,000, new business specific projects managed by the New Business organization, and large complex projects centrally managed by the Project and Contract Management organization. ComEd uses its Work Planning and Tracking Tool to develop its Five - Year New Business Long Range Plan for baseline work and large new business projects. New Business Long-Range Plan and annual budget development employ a new business economic model, historic baseline activity, and specific projects either centrally managed or managed by the New Business organization.

New Business determines its baseline annual budgets from the Load Forecast organization's economically based Activity Model, which predicts future residential service connections and relocation completions based on the prior five years of completions as reported by New Business, combined with Load Forecast's economic activity data. New Business reviews the results of the model and adjusts and validates the plan and budgets, working with other ComEd internal organizations.

New Business personnel monitor large project lists to identify specific large new business projects to include in the long-range plan, making necessary adjustments based on their knowledge and working with residential and commercial property developers, government agencies, and the Large Customer Solutions organization. For New Business managed projects, project owners determine work scope, schedule, budget, and resource requirements for labor, contractors, and material, as well as project risks. The Category Owner reviews the information for inclusion in the Long-Range New Business Plan. The New Business Category Owner may include additional funding for unspecified emergent projects in the two- to five-year plan budgets. For Centrally Managed Projects, the New Business organization coordinates meeting with the Project and Contract Management to finalize the listing of Centrally Managed New Business into the Long-Range Plan.

4. Equipment Ratings

Ensuring equipment operation within equipment ratings comprises a central planning criterion. The "normal" load ratings applied for equipment reflect the maximum permitted loadings without causing thermal ageing, assuming distribution system operation with all facilities in service and with equipment out of service for maintenance or construction. The calculation of the normal ratings includes the effect of daily load cycles and seasonal ambient temperatures.

ComEd allows for loading its equipment to its short-term (generally two hours) and long-term (generally 24 hours) "emergency" equipment ratings for a limited number of times and durations, with allowable durations dependent on loadings prior to the emergency event. The emergency ratings are based on not exceeding established thermal ageing data, not causing excess conductor sag, and not otherwise damaging equipment. To prevent damaging equipment, ComEd transfers load by switching, by installing mobile or spare transformers, or by dispatching distributed or mobile generation.

5. *Peak Load Forecasting*

To develop capacity plans, ComEd regularly assesses the projected peak load on its feeders and substations. The peak load forecast considers a variety of factors, including weather, not all of which are completely predictable, such as projections of area peak load growth, new developments, types of customers, and other factors.

ComEd's Distribution Capacity Planners review load data, perform calculations, and project peak loads for feeders and substations. The Planners have responsibility for providing normal distribution system configuration and normal loadings for the short-term and the long-term by monitoring new business and unidentified load growth. The Regional Distribution Capacity Managers review the load forecasts in planning areas within each Region, and the Distribution Capacity Planning Manager approves the short-range forecasts and "owns" the Capacity Expansion Category and the short-range load forecasting process.

The Forecast Coordinator (FC) operates a load forecasting tool to support the Planners' summer peak load forecast process and the FC is responsible for reporting winter components that violate planning criteria. The New Business organization receives and responds to customer requests including site locations, new points of service, contracts, and cost estimates, and New Business communicates to Capacity Planning information related to future loading changes. Regional Engineering communicates facilities relocation requests by public authorities to Capacity Planning. Transmission Planning communicates transmission system changes that impact distribution capacity planning.

Capacity Planning uses its Area Planning Tool (APT) to illustrate and analyze feeder and substation loads and capacities, connectivity between circuits, substation transformers, and transmission circuits, and to show the effect on peak loads by planned load transfers, load additions, and other planned actions. Capacity Planning analyzes this data using its Load Forecasting Tool to coordinate load forecasts between planning areas, to improve feeder and substation load forecast accuracy within an area, and to normalize total system feeder forecasts with the overall corporate forecasts. ComEd's load forecasting tool uses a knowledge-based calibration method to minimize possible error in identified load additions. The load forecasting tool also allows Planners to become aware of unidentified growth based on historical load growth trends and on identified new business data.

Capacity Planners forecast summer peak loadings for one to six years to determine the need for proposed capacity projects for inclusion in capital budgets. The Planners validate peak loads for feeders, substation transformers, and substation terminals using the APT. The Planners input forecasted peak loads and configuration data, including amounts and locations of capacitors, and planned load transfers among feeder groups for the next one to three years and between substations for the next four to six years.

The Forecast Coordinator determines the future 90th percentile summer peak loads by zones for the following five years, using historical and current year peak load day weather data. The coordinator uses this 90th percentile weather to adjust peak load forecasts for hot weather duration on peak load days. The calculation employs a 10 percent risk that hot weather will cause the forecast peak load to be exceeded. The coordinator uses the load forecasting tool to determine the feeder components projected to be outside of the planning criteria for forecast winter peak loads for next winter.

The Forecast Coordinator and Area Planners review the APT list of feeders and substation terminals currently, or forecasted to be, loaded at 90 percent or more of allowable loading limits. This examination reviews possibly at-risk feeders and substations, or feeders and substations that may need capacity solutions. The Planner reviews sources of possible forecast error of at least 10 percent, including growth estimating error, not-yet-completed capacity relief projects, weather adjustment error, distributed generation capability, SCADA and metering issues, new business and customer load changes, capacitor issues, prior years load data errors, uncompleted reliability projects, and load shifts in networks. ComEd personnel examine the results of this review to identify opportunities to improve planning procedures, process, and training.

Before producing the official Capacity Plan, forecasts produced from the load forecasting tool set are compared with alternative load forecasting results. Once official, the forecast does not change unless a documented major change in load emerges.

6. *Area Capacity Planning*

ComEd prepares two-year distribution circuit load forecasts and five-year substation forecasts to allow time to complete capacity projects. ComEd develops its distribution capacity plans at the distribution capacity planning area level to ensure that all components on the distribution system undergo review for compliance with planning criteria. Capacity planning areas are typically bounded by barriers to feeder routes, such as rivers and interstate highways, and include a group of adjacent substations and the feeders supplied by those substations. Each planning area includes up to six substations and loads up to 600MW.

Area planners develop and propose various solutions to address components that violate or will violate planning criteria, including analyses of costs and consequences of not providing the solutions. These solutions might include transformer additions, distribution automation, new feeders or extensions, feeder switching, phase balance, and capacitor installations. Planners enter proposed circuit modification solutions into circuit connectivity and load transfer functions of the APT to verify proposed solution effectiveness and to compare alternative solutions.

Planners also review the conditions of substation transformers via the substation “health index” to determine whether to consider dual-purpose solutions that meet the need for capacity while improving the material conditions. Typically, the least cost solution is selected, with other solutions considered if justified. Planners then develop a pre-project and post-project Risk Score for the preferred solution, based on the merit or the net present value, of the solutions as required by the Strategy Project Risk Score Matrix.

Planners develop Area Capacity Plans, a planning area map and substation feeder map, and a summary of forecast feeder and substation loads before and after proposed projects. They also develop high level cost estimates for major substation and feeder projects planned for the following five years. ComEd conducts a screening and capital authorization processes for large projects, as described below.

7. *Substation Load Forecasting*

For forecasting substation transformer and terminal load growth, Planners roll up distribution circuits’ forecasted load growth, including circuit coincidence factors, for the next two years for the validation plan and for the next three years for the official plan. The Planners forecast substation terminal load growth for the next four to six years based on identified additions and load growth trends over the previous five years.

8. Long-Range Capacity Planning

Long-range distribution capacity planning allows Transmission and Substation Planning to develop long-range plans for transmission substations and lines (commonly referred to as 'bulk power') and to determine needs and locations of substations for supplying power to the distribution system. Determining new substation locations employs predicted planning area loads over the next 5, 10, 15, and 20 years, considering predicted total system load growth based on econometric models used by the Financial Planning organization and PJM. Land parcel availability, costs, and other considerations, including expected distributed energy resource (DER) interconnections apply as well. Expanding existing substations proves generally less expensive than constructing new substations. However, when new substations prove necessary, substations for 12kV feeders get placed on four- to six-mile centers and substations for 34kV feeders get placed on 10 to 15-mile centers.

C. System Performance Planning

Reliability engineers develop programs to improve reliability metrics by reducing outages and the effects of outages on customers. Chapter VII: *Distribution System Performance*, explains the methods and metrics used to measure customer interruptions and durations. ComEd's capital distribution automation program design seeks to improve automatic sectionalizing and restoration, which reduces the effect of unavoidable outages caused by like ageing equipment, trees, car pole accidents, animals, and severe weather. The engineers typically use a cost versus reliability benefit process to determine the most cost beneficial program activities and where to prioritize the application of reliability program activities. However, in some cases where pockets of poor reliability exist, for example, customers with excessive interruptions or durations, or one percent worst performing circuits (circuits with the worst reliability metrics), that require reliability mitigation projects, engineers may undertake reliability work that does not have the same cost-reliability benefits of major system-wide programs.

ComEd develops its long-range reliability plan based on the assessment of reliability drivers by cause, identifying programs that address reliability drivers and assessing the benefit versus cost of the programs. This development includes defining what aspects of reliability performance the work will positively affect, how feeders become selected for the programs, and what aspects merit attention in determining the annual scope of work.

Reliability engineers determine the benefits of applying a program or a mix of programs, such as installing mid-circuit reclosers and distribution automation (*e.g.,* smart grid schemes) to a circuit with low reliability. The engineers perform an estimate, based on feeder reliability history, the number of customer interruptions (CI) and the customer minutes of interruption (CMI) avoided for the following ten years by the application of the program or by the mix of programs. The engineers use an algorithm-based scoring process to identify which programs to apply and where to apply them. The system-wide programs are only applied to feeders where the benefit versus cost ratio reaches a justifiable level. The engineers track feeder reliability improvement to confirm that the spending has provided the estimated benefits over the ten-year time frame. The verifications/metrics include factual customer interruption and customer minutes of interruption avoided and impacts on reliability metrics. Like planning for capacity expansion, ComEd has formal capital project planning and authorizing processes for plant additions required to meet future reliability targets.

D. Corrective Maintenance Planning

Corrective Maintenance programs include servicing distribution and substation equipment, identifying equipment deficiencies, and upgrading or replacing equipment before failures cause customer interruptions. ComEd plans capital funded corrective maintenance budgets in its five-year long-range plan. Inputs include manufacturer data, historical maintenance template and costs, prioritized equipment condition and reliability issues, and emerging maintenance process and technology improvements. The Planning and Asset Management engineers, including equipment experts, develop the plans. ComEd adjusts the long-range plan when needs for major corrective maintenance projects such as a failing substation transformer emerge. Like planning for capacity expansion and for system performance, ComEd has formal capital project planning and authorizing processes for plant additions required to maintain its equipment.

E. Capital Projects and Program Screening and Authorization

ComEd applies screening and authorization processes to all capital projects and programs, including capacity expansion, facilities relocation, new business connections, corrective maintenance, and system performance capital plant categories.

1. Screening and Authorization

ComEd's capital screening and authorization processes for projects and programs costing more than $100,000 in capital and associated O&M costs include systematic evaluations and authorizations of proposed and on-going capital projects and programs, intended to allow senior management the ability to control a project's scope, cost, contract strategy, budget development, schedule, and other long-range planning processes. The primary goals of the process seek to ensure that:

- The technical merits of each project or program remain balanced with economic benefits and goals.
- Projects and programs undergo research, development, planning, review, and authorization by senior management before resource commitment.
- Decision points get established for approving further funds, as project details evolve.

ComEd's project approval and authorization process includes three phases. Phase 1 authorization requires the completion of a project feasibility study and engineering work required to establish objectives, scope, success criteria, and viability of the project. Initial project cost estimates for Phase 1 must fall within +/- 50 percent of final costs. Once authorized, the process proceeds to Phase 2, which requires completion of final designs and engineering, the procurement of long lead time materials, site preparation, and the start of civil construction. For Phase 2, cost estimates must fall within +/- 25 percent of final costs. After Phase 2 authorization, the approval process goes to Phase 3, the project construction to completion phase. Re-authorization of Phase 3 is required if project costs overrun authorized amounts by 10 percent and $100,000.

Projects under $500,000 (Type 0 projects) require only Category Manager level authorization. Although all projects over $100,000 must go through the Phases 1, 2, and 3 authorization process, proposed projects over $1.5 million (including direct and indirect costs) must first, before any authorization, be screened by the Investment Strategy, Finance, and Risk organizations. Screening reviews the original project requests and justifications. Based on costs, complexity, and risk, they screen the projects and assign them into types of projects that then determines the management level required to approve and authorize each project. Type I consist of low-risk projects over $1.5 million where ComEd has had a history of successfully completing similar types of projects. Type II consist of more complex, higher risk, projects over $1.5 million. Type III projects fall within ComEd's Utility of the Future construct, which covers projects for implementing emerging technologies over $1.5 million. This construct represents a common designation among many utilities typically connotes efforts to bridge current system capabilities to one that is more customer centric, decentralized, and largely served by renewable technologies and demand management capabilities. Approvals of capital programs involving high volume smaller, but frequently performed work, at the core of ComEd's business, become determined though the Utility Programmatic screening process.

The PCC meets once a month to review proposed and current projects, except Type 0 projects, to consider technical and business alternatives, determine the validity of the business need of proposed projects, determine whether the proposed solution is the best, most cost effective solution, determine that identified resources are accurate, and to ensure that work management, business planning, project authorization, and project management are integrated in the assessments. The PCC makes recommendations regarding changes to the proposed work scope to meet the challenges to the overall capital budget.

As the levels of estimated costs of proposed projects increase, so does the management level required to authorize the projects, as shown in the following table. Authorization levels range from the Category Manager level for under $500,000 projects to the Exelon Board of Directors level for projects exceeding $200 million.

Project Authorization Limits

Project Cost (Direct + Indirect)	Category Manager	Department Vice President	COO / PCC Chair	Utility President / CEO	Exelon Utility CEO	Exelon CEO	Utility BOD	Exelon Finance Risk Committee	Exelon BOD
< $500K	Authorize								
> $500K to $5M		Authorize							
> $5M to $15M			Authorize						
> $15M to $25M			Recommend	Authorize					
> $25M to $50M			Recommend	Recommend	Authorize				
> $50M to $100M			Recommend	Recommend	Recommend	Authorize	Authorize		
> $100M to $200M			Recommend	Recommend	Recommend	Recommend	Recommend	Authorize	
> $200M			Recommend	Recommend	Recommend	Recommend	Recommend	Recommend	Authorize

2. *Post Authorization Work Plan Prioritization Process*

After ComEd management approves and authorizes program and project investments, but before scheduling the work, management prioritizes the work using the work plan prioritization process to identify the need, assess the risk score, and prioritize system investments and initiatives. The process design seeks to ensure that value added by the projects is consistent with objectives, and provides senior management with the means for leading the decision-making process to optimize the portfolio of investments. The process ensures that projects are prioritized consistent with approval and authorization processes and that the desired delivery system functionality is achieved at least cost and without causing safety, environmental, or reliability issues. The Asset Performance and Investment Strategy team uses the work plan prioritization process to review the projects and to assess the risk scores; and to challenge assumptions to determine the probability of failure and the probability of consequences. This process does not apply to emergent work or work required by the regulatory agency.

XI. Database

A. Overview

We created a data baseline, or database, for ComEd information using Microsoft Access and including:

- Refined data (tables) that house the data
- Queries that enable the efficient extraction of useful data sets
- A user interface that enables the user to specify how those queries produce data and enables efficient export of the queried datasets to Excel for data analysis.

In general, the ComEd and AIC databases are similar, with many common features and general data structure. The companies diverge with respect to the specific data that they provided in terms of the years for which data was available, data format, level of detail, and in some cases data availability.

The goals of this database include highlighting the larger individual projects performed and collections of smaller individual projects, often undertaken on a continuing, programmatic basis over our study period. As this report shows, groups of smaller capital projects or O&M measures cyclically undertaken comprise in their own right very large sources of expenditure and material contributors to changes in system configuration, condition, and performance.

B. Data Source

On September 22, 2021, prior to Liberty's engagement, Staff issued to both companies twelve relatively broad data requests. The requests solicited both quantitative and qualitative information. Responses were voluminous. Once retained, Liberty issued its own series of data requests, including a key request that asked the ComEd to complete a Liberty-designed Excel-based data template eliciting a variety of distribution system information. Liberty subsequently issued additional data requests, some of which contained data ultimately incorporated into the database. Other responses were more descriptive, or narrative based (*e.g.*, procedures, processes, guidelines), and are not reflected in the data baseline. Relevant data from both sources (*i.e.*, data responses to Staff and Liberty) are the foundation of the data baseline, or database.

1. Data Template Content

The data template requested a variety of data pertinent to grid assessment, broken into categories. ComEd populated the templates with data to the extent it was available in a useful form. The data template requested information in the following general categories:

- System Condition
- System Configuration
- Transmission and Sub-Transmission Circuits
- Planning
- Spend/Impact
- Distribution Circuits
- Customer Information Systems
- Advanced Metering Infrastructure (AMI)

- Outage Management System (OMS)
- Distributed Energy Resources (DERs)
- Substations.

2. Data Refinement

Key to the development of the database was data refinement, which essentially entailed:

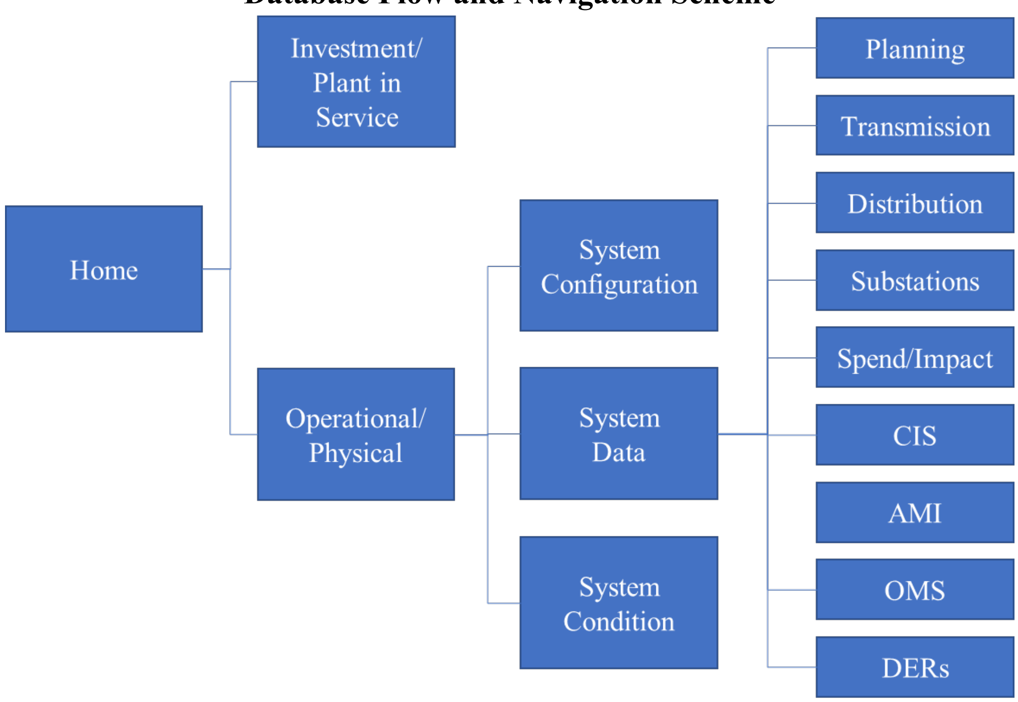
- Collecting spreadsheet templates
- Identifying relevant data from Staff responses to incorporate into the database
- Adjusting data to accurately reflect the difference between "no data" and an entry of zero where applicable
- Capturing text notes and data source explanations
- Turning each table into a relational data table
- Importing the relational data tables into Access.

The Data Statistics subsection, below, summarizes the data in terms of which parameters were provided and for what years, providing a high-level snapshot of data completeness.

C. Access Database

The database in a Microsoft Access file that requires Microsoft Access to run. Once opened, the database is a comprehensive and self-contained information system containing all the data refined for review, query, and analysis. It was developed to be used through a built-in user interface with a flow of data as follows:

Database Flow and Navigation Scheme



In addition to the refined grid data, the database contains a custom user interface that allows the user to select from wide variety of query parameters accomplished through a series of drop-down menu items with selectable inputs. Once the query parameters are set, the user presses the "Query" button to view the results on screen and export them to Excel. The Interface subsection below describes the interface in more detail.

D. Data Statistics

Liberty compiled a set of statistics for the database, summarized in the following table. This displays the table category, table name, the source of its data, and the number of records it contains.

Database Table and Record Summary

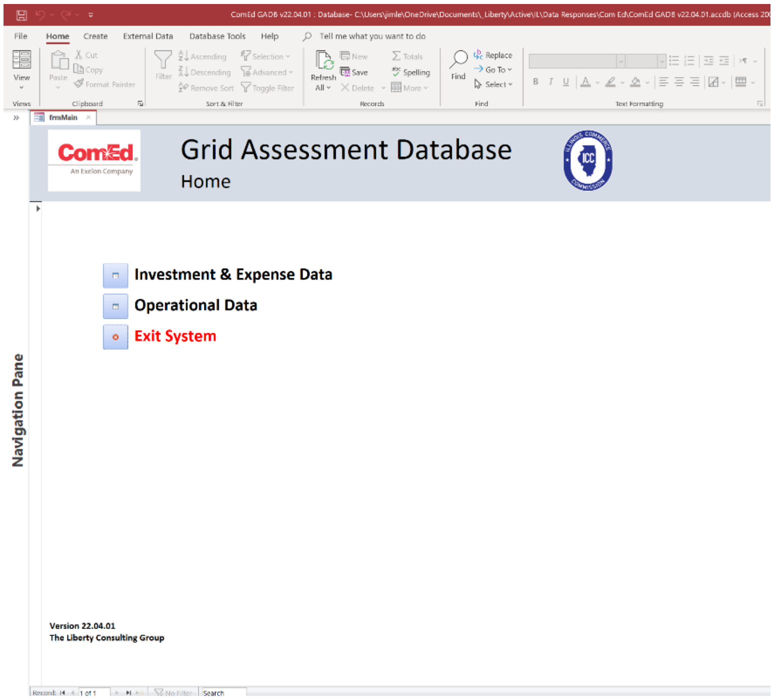
Category	Name	Source	Records
AMI	tblAMI	Liberty 1.01_Attach 1	198
CIS	tblCIS	Liberty 1.01_Attach 1	1,000
Customers	tblSysConfCust	Liberty 1.01_Attach 1	54
DERs	tblDER	Liberty 1.01_SUPP Attach 1	612
Distribution Circuits	tblDistCirc	Liberty 1.01_Attach 1	1,179
Investment	tblInvestPlantAdditions	Liberty 2_Attach 1	9,242
Investment Detail	tblInvestProjects	Liberty 8_Attach 1	499
O&M	tblOMExpense	Liberty 3_Attach 1	3,087
OMS	tblOMS	Liberty 1.01_Attach 1	45
Planning	tblPlanning	Liberty 1.01_Attach 1	265
Reliability	tblSysConfReliability	Liberty 1.01_Attach 1	270
Spend/Impact	tblSpend-Impact	Liberty 1.01_Attach 1	675
Substations	tblSysCondSubstCount	Liberty 1.01_Attach 1	112
Substations	tblSysConfSubstations	Liberty 1.01_Attach 1	36
System Condition - Detail	tblSysCondSubstFieldOpAreas	Liberty 1.01_Attach 1	4
System Condition - Interruptions	tblSysCondInterruptions	Liberty 6 _Attach 1	144
System Condition - Multiple Categories*	tblSysCondBasic	Liberty 1.01_Attach 1	3,060
System Configuration - Detail	tblSysConfCircuitsCount	Liberty 1.01_Attach 1	63
System Configuration - Detail	tblSysConfCircuitsMiles	Liberty 1.01_Attach 1	54
System Configuration - System Loads	tblSysConfPeakLoad	Liberty 1.01_Attach 1	9
Transmission Circuit Miles	tblSysCondTranSubTranCircuits	Liberty 1.01_Attach 1	351
Vegetation	tblSysConfCircuitsVeg	Liberty 1.01_Attach 1	18
Total Records			**20,977**

**Categories include wood pole counts, ages, and actions; substation transformer counts, ages, and actions; circuit breaker counts, ages, and actions; cable counts, ages, and actions; distribution circuit transformers and recloser events; equipment inspection completions and completion rates.*

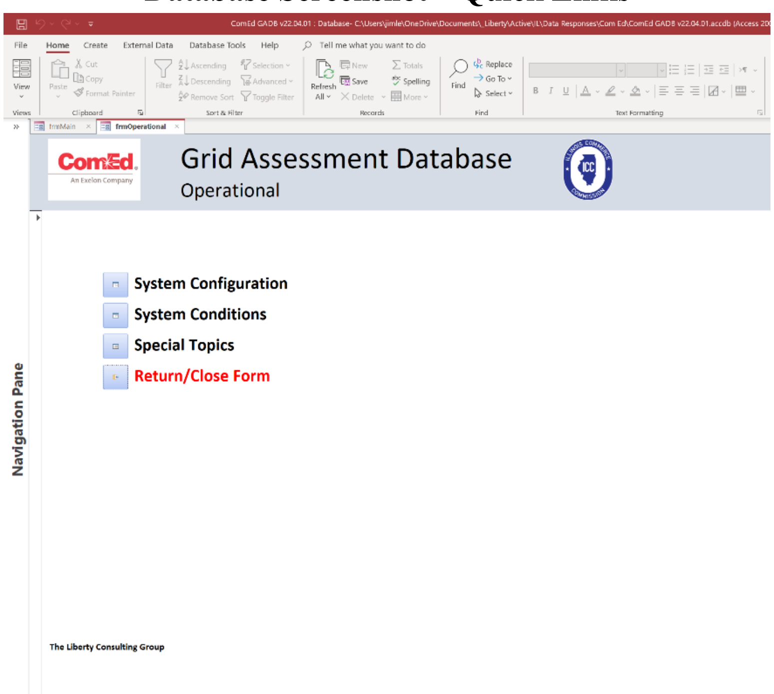
Interface

The user interface enables the user of the database to navigate to specific types of data, select entire data tables for export, and query for specific data. The following screen shots show the basic structure of the interface.

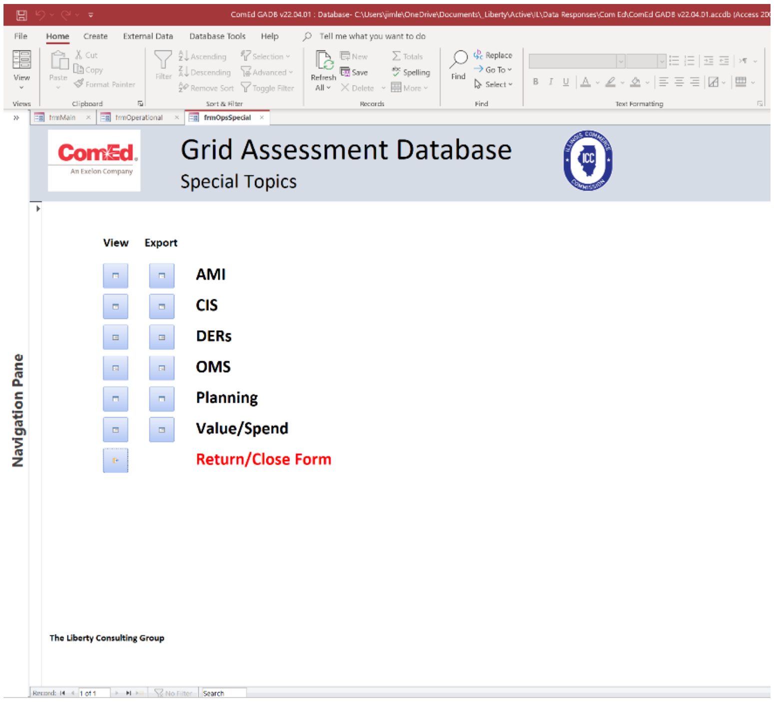
Database Screenshot – Home Page



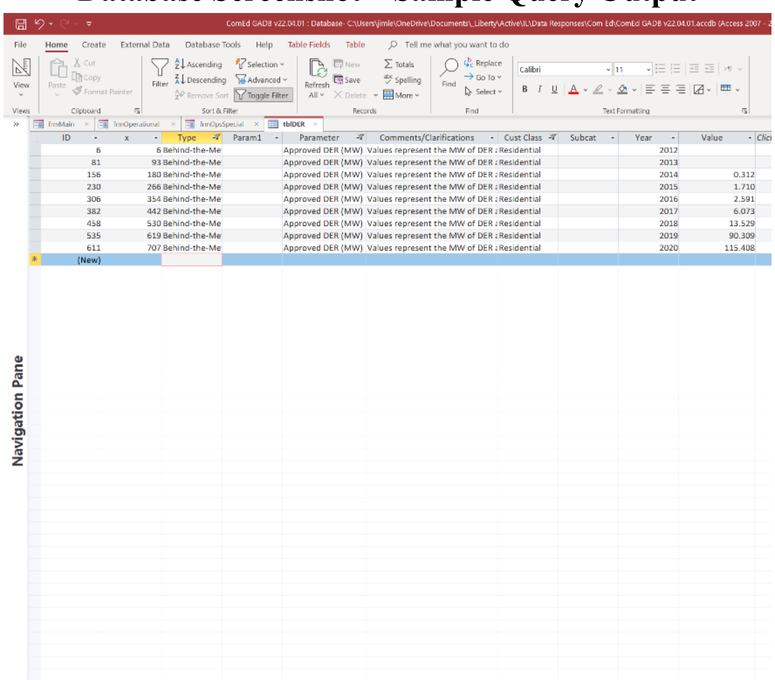
Database Screenshot – Quick Links



Database Screenshot – Querying Capabilities



Database Screenshot – Sample Query Output



Appendix A: List of Acronyms

Acronym	Full Name
AC	Air Conditioner
AMI	Advanced Metering Infrastructure
ATO	Automatic Throw Over
CAIDI	Customer Average Interruption Duration Index
CERT	Customers Exceeding Reliability Targets
CI	Customer Interruptions
CM	Corrective Maintenance
CMI	Customer Minutes of Interruption
DA	Distribution Automation
DC	Distribution Center
DER	Distributed Energy Resource
EAB	Emerald Ash Borer
EIMA	Energy Infrastructure Modernization Act
EWED	Extreme Weather Event Days
GPS	Global Positioning System
HAN	Home Area Network
HVD	High Voltage Distribution
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
IEEE	Institute of Electrical and Electronics Engineers
IFTTT	If This Then That
IIP	Infrastructure Investment Plan
IT	Information Technology
IVR	Interactive Voice Response
kV	Kilovolts (1,000 volts)
kW	Kilowatt (1,000 watts)
kWh	Kilowatt Hour
MCIP	Material Condition Improvement Plan
MDMS	Meter Data Management System
MW	Megawatts (1,000 kW)
N-1	“N” denotes normal configuration, “-1” one supportive element out.
NERC	National Electric Reliability Corporation

NESC	National Electrical Safety Code
NIST	National Institute of Standards and Technology
NOC	Network Operations Center
O&M	Operations and Maintenance
OH	Overhead
OMS	Outage Management System
OTA	Over-the-Air
PCC	Project Concurrence Committee
PdM	Predictive Maintenance
PJM	Pennsylvania, New Jersey, Maryland Interconnection LLC Mid-Atlantic Power Pool
PM	Preventive Maintenance
PMO	Project Management Office
PTS	Peak-Time Savings
RFP	Request for Proposal
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGAC	Smart Grid Advisory Council
SS	Switching Station (Substation)
T&D	Transmission and Distribution
T&S	Transmission and Substation
TDC	Transmission to Distribution Center (Substation)
TSS	Transmission Substation
UFE	Unaccounted For Energy
UG	Underground
URD	Underground Residential Distribution
VLF	Very Low Frequency
VM	Vegetation Management
VO	Voltage Optimization
Volt-VAR	Volt-Amperes Reactive
WPC	Worst Performing Circuits